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# Dickey-Lincoln School Lakes Project Power Alternatives Study : Task 1 Report

Acres American Incorporated

# DICKEY-LINCOLN SCHOOL LAKES PROJECT

## POWER ALTERNATIVES STUDY
## TASK 1 REPORT

JULY 1976

PREPARED FOR

CORPS OF ENGINEERS

NEW ENGLAND DIVISION

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# 1 - INTRODUCTION

This report presents the results of Task 1 of a study undertaken by Acres American Incorporated to evaluate alternative methods of providing electrical energy in lieu of the Dickey-Lincoln School Lakes Project. It is understood that this report will ultimately become part of the "Environmental Impact Statement" for the project. This work has been undertaken under the terms of Contract No. DACW33-76-C-0047 between the New England Division of the Corps of Engineers, and Acres American Incorporated of Buffalo, New York, dated January 23, 1976.

The proposed Dickey-Lincoln School Lakes Project (referenced hereafter as the "Dickey-Lincoln Project") is a hydroelectric project to be located on the upper reaches of the St. John River in Maine, near the confluence with the Allagash River. The currently planned generating capacity to be installed at the project is 830,000 kW with the possibility of incorporation of pumped storage features to bring the total capacity to as much as 1,210,000 kW*. The primary purpose of the Dickey-Lincoln Project will be to provide, with other existing and planned power and energy storage facilities, sufficient generating capability to meet the expected capacity and energy requirements of the six New England states. The currently planned completion date for Dickey-Lincoln is not earlier than 1986.

## 1.01 - Terms of Reference

The specific scope of work for Task 1 of the study is set out in Appendix A to the contract. The primary subtasks may be summarized as follows:

(a) Consult with Corps of Engineers to obtain project data;

(b) Review and select appropriate mathematical simulation program;

(c) Develop list of alternatives to Dickey-Lincoln;

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* "Dickey-Lincoln School Lakes, Maine, Fact Sheet", U. S. Corps of Engineers, October 1975. (See also Figure 1.1)

(d) Develop load forecasts;

(e) Submit report.

The results of the studies undertaken to meet these subtasks are presented in Chapters 3, 4, and 5 of this report.

## 1.02 - Report Content

It is intended that this report will ultimately become part of a complete report of the Power Alternatives Study. Chapter 1 will be revised accordingly to cover the entire report, and Chapter 2, an overall summary, will be prepared as Task 5 of the study. It is anticipated that Chapter 2 will eventually become the section of the Environmental Impact Statement which deals with alternatives to the proposed action.

The primary subtask -- and the one upon which the results of the balance of the study will depend -- has been the examination of the projected load growth of the New England States. This part of the study has centered around the load forecast prepared by NEPOOL, the body currently responsible for the coordination of system planning in New England. The examination of this forecast, which included a review of the primary component inputs provided by the various private and public utilities which together make up the New England Power System, is described in Chapter 3 of this report.

Chapter 4 deals with the preliminary assessment of possible alternatives to the Dickey-Lincoln Project. Because of the wide ranging power benefits attributable to hydro/pumped storage projects such as Dickey-Lincoln, as wide a spectrum as possible of alternatives has been examined. Information as to their characteristics has been drawn from most recently published data, from research and development projects currently underway, and from discussions with manufacturers and suppliers. By the application of criteria related to the potential for the development of the various types of facilities for replacement of Dickey-Lincoln within the 1985/1990 time frame, a number of specific alternatives have been identified for detailed evaluation.

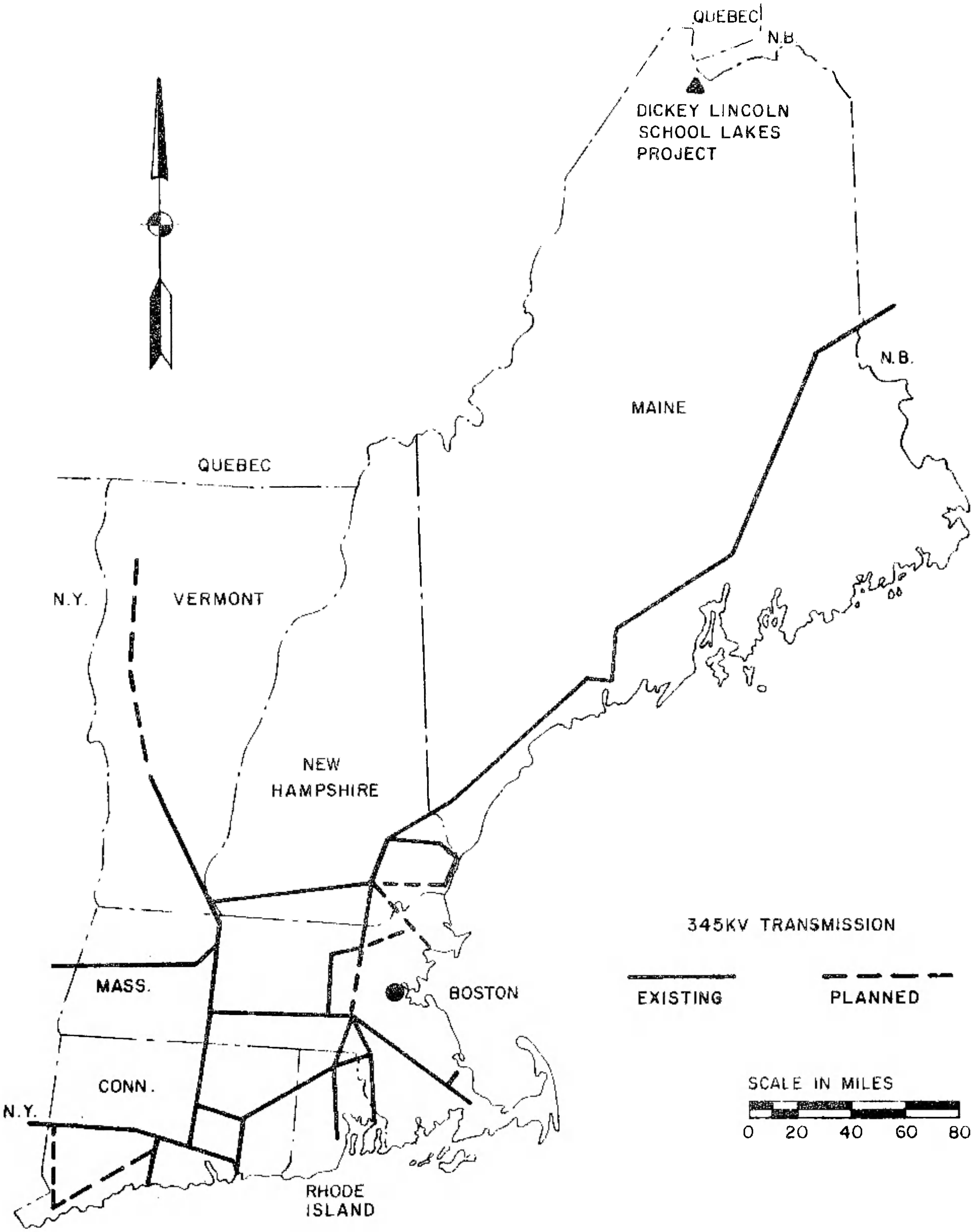



FIGURE 1.1
NEW ENGLAND SYSTEM

In Chapter 5 the results of a careful survey of available mathematical system simulation programs are presented. The survey encompassed programs of various types producing a variety of output data. Discussions were held with representatives of the more promising programs, and a specific program selected for use in the subsequent evaluation tasks.

Chapters 3 and 5 will be further expanded to include the results of Tasks 2 and 3 when these are complete, and Chapter 6 will cover the environmental impact studies also to be undertaken as part of Task 2. Chapter 7, which will be a general overview of the complete study, will be prepared as part of Task 4.

# 3 - LOAD FORECASTS FOR NEW ENGLAND

Over the years, it has been increasingly taken for granted that electrical energy should be available to virtually anyone who needs it, when they need it. This has made particularly onerous the task of electrical utilities in estimating future demands and ensuring that appropriate provisions are made to satisfy these demands. Because of the lengthy period needed to build generating facilities, it has required that decisions be made several years before such facilities are required to be commissioned. For example, hydro and conventional thermal plants now require as much as 5 to 7 years for planning, siting, environmental and socio-economic studies, design, and construction. Nuclear facilities require even longer -- typically 10 to 13 years. Because of such lengthy lead times, an electrical utility must attempt to forecast probable demand patterns several years into the future (typically 10 to 20 years).

In this Chapter the assessment of the probable demand patterns in New England through the year 2000 is described. A Summary of the Chapter follows in Section 3.01. A review of the characteristics of demand patterns for a typical large utility system, and a summary of forecasting procedures as they are applied in New England, is presented in Section 3.02. The historical trends of electrical load growth are reviewed in Section 3.03, together with an assessment of recent forecasts which have been made for future growth in New England. In Section 3.04 recommendations are developed for adoption of forecasts to be used in the generation expansion plan for New England.

## 3.01 - Summary

System generation future expansion plans require reasonably accurate projections of future capacity and energy demands. Procedures for forecasting have frequently been based on projecting historical sectoral trends (residential, commercial, industrial). Such techniques have proven unreliable in recent unsettled conditions in the power supply industry. Various other approaches to forecasting are now becoming more favored, such as econometric analysis of consumer patterns and overall energy needs by means of mathematical models.

### 3.01.1 - New England Demand

Forecasting in New England is complicated by the extremely varied structure of the industry, which comprises nearly 150 organizations in six states. The New England Power Pool (NEPOOL) was set up in 1966 to coordinate and plan the power supply industry for the whole region. NEPOOL produces peak load forecasts for the region on a six-monthly basis.

The cost of electricity in New England, which fell from 3.6 cents per kWh in 1950 to 2.6 cents in 1970, has increased significantly in recent years. The 1973 Arab oil embargo has compounded this trend. As a result, trends in demand for peaking power and energy have changed significantly. The 7.6 percent average annual growth in peak load experienced between 8,100 MW in 1965/66 and 13,500 MW in 1972/73 reversed itself in 1973/74 (12,900 MW) and has since slowly recovered to 13,900 MW by January 1976, an average growth from 1973/74 of 3.8 percent. Energy demand which in 1973 was 68.4 GWh and had been growing at a rate of 8 percent per annum, has shown a similar decline to 66.9 GWh in 1974. However, a return to a positive growth rate is currently indicated. Load factors which had also increased to 64.2 percent by 1974, have also fallen to little more than 60 percent.

Demand in New England is mostly centered on the two major population areas of Massachusetts and Connecticut, which consumed 72 percent of electric energy demand in 1974. Demand has expanded primarily in the residential and commercial sectors of the economy which together accounted for 67 percent of demand in 1974.

The NEPOOL peak load forecast published in January 1976, predicts an average 5.5 percent annual growth rate from 13,908 MW in January 1976 to 25,105 MW through 1986/87. The total energy demand in 1986 is forecast by NEPOOL to be 133,695 GWh at 60.8 percent load factor. Long-range planning is currently based on a maximum 5.5 percent growth rate to 53,834 MW in 2000/01.

### 3.01.2 - Major Utility Forecasts

The NEPOOL forecast presents a summation of the forecast of all utilities in the New England region. Eight of the largest utility groups accounted for nearly 85 percent of total demand of 13,908 MW in 1976:

- Northeast Utilities (NUS), 25.4 percent;
- New England Electric System (NEES), 20.1 percent;
- Boston Edison (BE), 12.4 percent;
- Public Service Company of New Hampshire (PSCNH), 7.4 percent;
- Central Maine Power Company (CMP), 6.9 percent;
- United Illuminating Company (UI), 5.7 percent;
- New England Gas and Electric Association (NEGEA), 3.8 percent;
- Central Vermont Public Service Corporation (CVPSC), 2.6 percent.

The individual forecasts of seven of these groups (NEGEA excluded) have been examined. The results of this examination are shown in Table 3.1.

### 3.01.3 - Future Load Growth

The utilities, recognizing the increasing difficulties in obtaining reliable forecasts on the basis of traditional techniques, are generally supporting NEPOOL in its efforts to develop an econometric forecasting model. The current NEPOOL forecast is intended as a basis for planning future system capability and as such is considered appropriate. However, for examination of the economic impact of the Dickey-Lincoln Project, a more conservative approach to load forecasting would seem to be desirable.

An examination of the sensitivity of the NEPOOL forecast to changes in individual utility sectoral energy demands indicates that the peak load growth could be reduced to as low as 5.0 percent. However, for study purposes a 5.2-percent value is recommended through 2000/20001. An improvement in load factor to 62 percent is entirely feasible by 1986, which is equivalent to a corresponding 5.5 percent growth in annual energy consumption. This growth rate is also recommended for study purposes. Peak loads and energy forecasts on this basis are:

| Year | Winter Peak Load (MW) | Year | Annual Energy (GWh) | Load Factor (%) |
|---|---|---|---|---|
| 1985/86 | 23,090 | 1985 | 124,826 | 61.8 |
| 1990/91 | 29,751 | 1990 | 163,142 | 62.7 |
| 1995/96 | 38,334 | 1995 | 213,220 | 63.6 |
| 2000/01 | 49,392 | 2000 | 278,671 | 64.5 |

## 3.02 - Requirements of Forecasting

An electric utility must be able at all times to supply both the capacity and energy needs of its many customers. Because of the considerable length of time required to bring a generating facility from the planning stage to on-line generation, it becomes important to make as accurate projections as possible of probable future capacity and energy demands for an extended period into the future. These load and energy forecasts then become the basis for generation expansion planning and for negotiating power contracts with neighboring utilities.

### 3.02.1 - Demand Patterns

The demand for electric power in a system varies continuously with time (see Figure 3.1A). During any 24-hour period, for example, there will be periods of high demand, such as the late morning when electricity use in residential, industrial, and commercial buildings is high. During other times of the day, demand may be quite low, as for instance, during early morning hours. The maximum demand is known as the "peak". Peaks are identified in relation to different periods of comparison, i.e. daily, weekly, monthly, seasonal, or annual.

The demand pattern will vary from day to day. For example, demand on sequential days will be different because of different industrial, residential, and commercial use patterns, etc. This pattern may be influenced by many factors -- such as different weather conditions (which, in turn, affect heating and cooling requirements), varying manufacturing intensity, evening shopping during certain days of the week, etc. Demand tends to be lower on weekends than on weekdays, and lower in summer than in winter (although this seasonal variation is decreasing due to higher air conditioning loads in the summer).

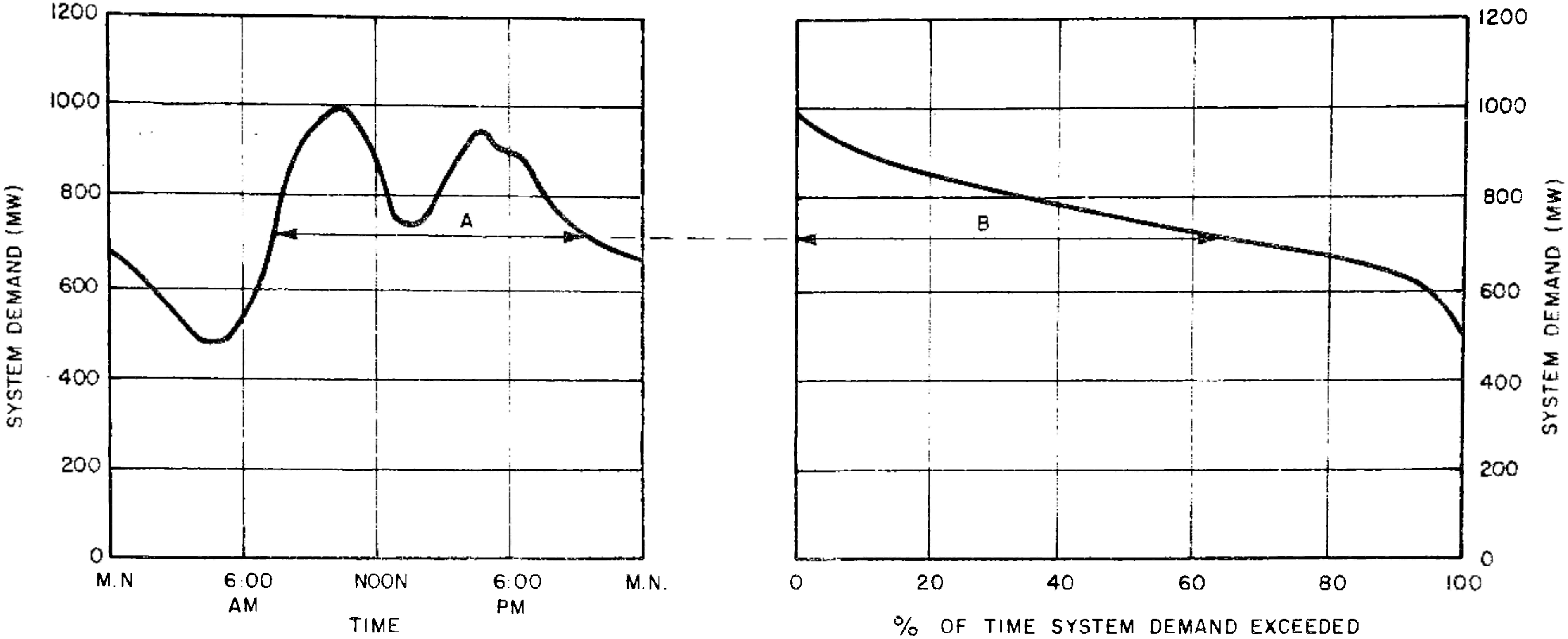
A graph of demand versus time is by itself not particularly useful for planning purposes, as it does not lend itself to mathematical analysis. In its place, utilities normally use a diagram referred to as a load-duration curve (see Figure 3.1B), which is a representation of the percentage of the time that system demand is equal to or greater than the associated power value (or, simply, an array of load values in descending order). A load-duration curve may relate to a period as short as a

TABLE 3.1

SUMMARY OF CURRENT NEW ENGLAND PEAK LOAD AND ENERGY FORECASTS TO 1986/87

| | | | | NEPOOL Forecast Winter Peak Load (MW) (Jan. 1, 1976) | | | Forecast Sectoral Energy Demands | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Residential | | Commercial | | Industrial | | |
| Utility | Principal Areas Served | Annual Energy Gwh 1975 | Load Factor | Jan 76 (Dec 75) | Jan 87 (Dec 86) | Average Annual Growth (%) | Proportion (%) | Growth (%) | Proportion (%) | Growth (%) | Proportion (%) | Growth (%) | Remarks |
| NUS | Mass. Conn. | 19,643 | 63.3 | 3,540 | 5,761 | 4.5 | 37.5 | 3.8 | 26.3 | 6.4 | 26.7 | 4.7 | Growth adjusted downwards from detailed econometric forecast 4.7%. |
| NEES | Mass. N.H. R.I. | 15,214 | 62.0 | 2,796 | 5,481 | 6.3 | -- | -- | -- | -- | -- | -- | Median of "high" and "low" band width projections. |
| BE | City of Boston | 9,490 | 62.9 | 1,723 | 3,056* | 5.3 | 27.6 | 5.7 | 44.0 | 7.0 | 18.0 | 4.4 | Conventional sectoral/economic forecast for 5-year period only. |
| PSCNH | N.H. | 4,925 | 54.6 | 1,030 | 2,241 | 7.3 | 44.0 | 8.4 | 13.0 | 6.5 | 42.0 | 7.4 | Based on 1974 detailed econometric analysis. |
| CMP | Me. | 5,294 | 58.5 | 956 (1,033) | (1,969) | 6.0 | 39.6 | 6.2 | 21.2 | 9.0 | 37.7 | 4.0 | Conventional sectoral/economic forecast. |
| UI | Conn. | 4,211* | 63.0* | 792 (763) | (1,223) | 4.4 | -- | -- | -- | -- | -- | -- | "Low" of band width projections. |
| CVPSC | Vt. | 1,689 | 54.2 | 356 | 530* | 3.7 | 45.2 | 5.5 | 10.1 | 5.0 | 28.6 | 3.5 | Conventional sectoral/economic forecast. |
| Others | -- | 13,034* | 56.3* | 2,645 | 4,395 | 4.7 | -- | -- | -- | -- | -- | -- | By difference. |
| All Utilities | New Eng. | 73,500* | 60.6* | 13,838 | 24,856 | 5.5 | | | | | | | |
| Losses | -- | -- | -- | 70 | 249 | -- | | | | | | | |
| Total Demand | -- | -- | -- | 13,908 | 25,105 | 5.5 | | | | | | | |

* Extrapolated or estimated.




(A) TYPICAL DAILY DEMAND PATTERN

(B) LOAD DURATION CURVE

NOTE: $B(\%) = \frac{A\ (HOURS)}{24} \times 100$

FIGURE 3.1
DAILY LOAD CURVES

day or as long as a year. For the hypothetical daily load curve illustrated in Figure 3.1, system demand is shown to be in excess of 500 MW, 100 percent of the time. Above that value, system demand corresponds at a progressively lower percentage and eventually approaches zero percent at 1,000 MW, which is the instantaneous peak system demand.

A major advantage in using a load-duration diagram is that it can be defined for any length of time. In Figure 3.1 the diagram was developed from a typical daily time-based demand pattern, and could therefore be referred to as a daily load-duration graph. However, it is also possible (by following the same procedure in principle) to define weekly, monthly, and annual load-duration curves.

A load-duration curve contains some very useful information for planning purposes. First of all, it shows the maximum demand of the system and thereby provides an indication of the generating capacity which is needed.

Secondly, the diagram provides a presentation of energy needs. The area under the curve is a measure of the total energy consumed during the representative time interval. In this particular diagram, for example, the average amount of energy would be about 750 MWh per hour. If this were a monthly or annual load-duration diagram, the energy consumption (in terms of MWh) would be then simply this average value multiplied by the number of hours in a month, or in a year, respectively.

Thirdly, the diagram provides a basis for defining "system load factor" (which is more often referred to simply as "load factor"). This factor defines the ratio of average power demand to maximum power demand. In Figure 3.1, for example, these values are 750 MW and 1,000 MW respectively, and the load factor is therefore 0.75 (or 75 percent).

There are several aspects pertaining to load factor which are of special interest to utility planners. Firstly, an annual load factor which is of the order of 80 percent or larger is considered to be high, and usually implies a large amount of continuous demand (which would normally come from the industrial sector). On the other hand, an annual factor of about 50 to 60 percent implies a cyclical demand pattern. Because of more fluctuating demand patterns of residential users (relative to industrial), such a low load factor is often associated with systems dominated by residential users. In the New England system, industrial users account for only 30 percent of total system demand, while residential and commercial users account for 67 percent (see Table 3.2). In recent years, typical annual load factors in New England ranged from 57 percent to 64 percent.

### 3.02.2 - Forecasting Procedures

There are several forecasting procedures which are used by electric utilities for predicting future power and energy demands. The first of these is simply a projection of historical demand trends into the future. If historical patterns have been reasonably uniform and consistent, this can be quite accurate for short-term trends (say 2 or 3 years). However, this technique can lead to significant error for longer term projections, especially if no attempt is made to examine those underlying factors which have contributed to historical growth and which, in themselves, could change in future.

The second demand projection procedure is based on incorporating various economic and policy indicators. For example, electrical demand may be related to gross national product, real economic growth, per capita income, etc.

While these two procedures are based on assessing overall growth in electrical demand, there are other approaches which are more detailed, and tend to be more accurate for planning purposes. The two most common approaches are regional forecasting and sectoral forecasting. For regional forecasting, an independent projection is developed for each of several regions. These are then combined to produce a total forecast. For sectoral forecasting, each of the various demand sectors (residential, commercial, industrial, etc.) are assessed independently, and these are then also combined to produce a total forecast. It would be expected, of course, that the end results of regional and sectoral projections should produce similar answers. Both techniques are in common use by many utilities and the dual approach provides a convenient cross check on overall results, as well as being independently useful for assessing more detailed needs.

A technique which has been used in recent years is based on an energy framework concept. By examining the overall energy needs of a region, the relative role of electrical energy within such a framework can then be assessed. By projecting overall energy demand into the future, and by examining the progressive shift from one energy form to another (oil heating to electrical heating, for example), relative demands for the various energy forms can also be simultaneously forecast. This provides a check to ensure that longer term demand projections for electrical energy are consistent with overall energy demand trends. Account may also be taken by this technique of a number of other factors which may influence energy demand, for instance population and general economic trends. In recent years, this overall approach has been developed in the form of econometric mathematical models. However, no fully developed and proven model is known to be in use at this time.

## 3.03 - Load Forecasting in New England

Demand forecasting for the New England region is particularly handicapped by the complexity of the structure of its utility industry. Firstly, the region includes six states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Secondly, there are nearly 150 individual organizations that provide electricity to New England customers. Figures 3.2 and 3.3 illustrate how the industry is structured and spread in terms of facility ownership, types of utility corporations, size of firms, and types of generating facilities.[1]

### 3.03.1 - Regional Planning

Although the power industry in New England is composed of both public and private firms, the investor-owned utilities meet the largest proportion of the

1. For General References, see page 3-52.

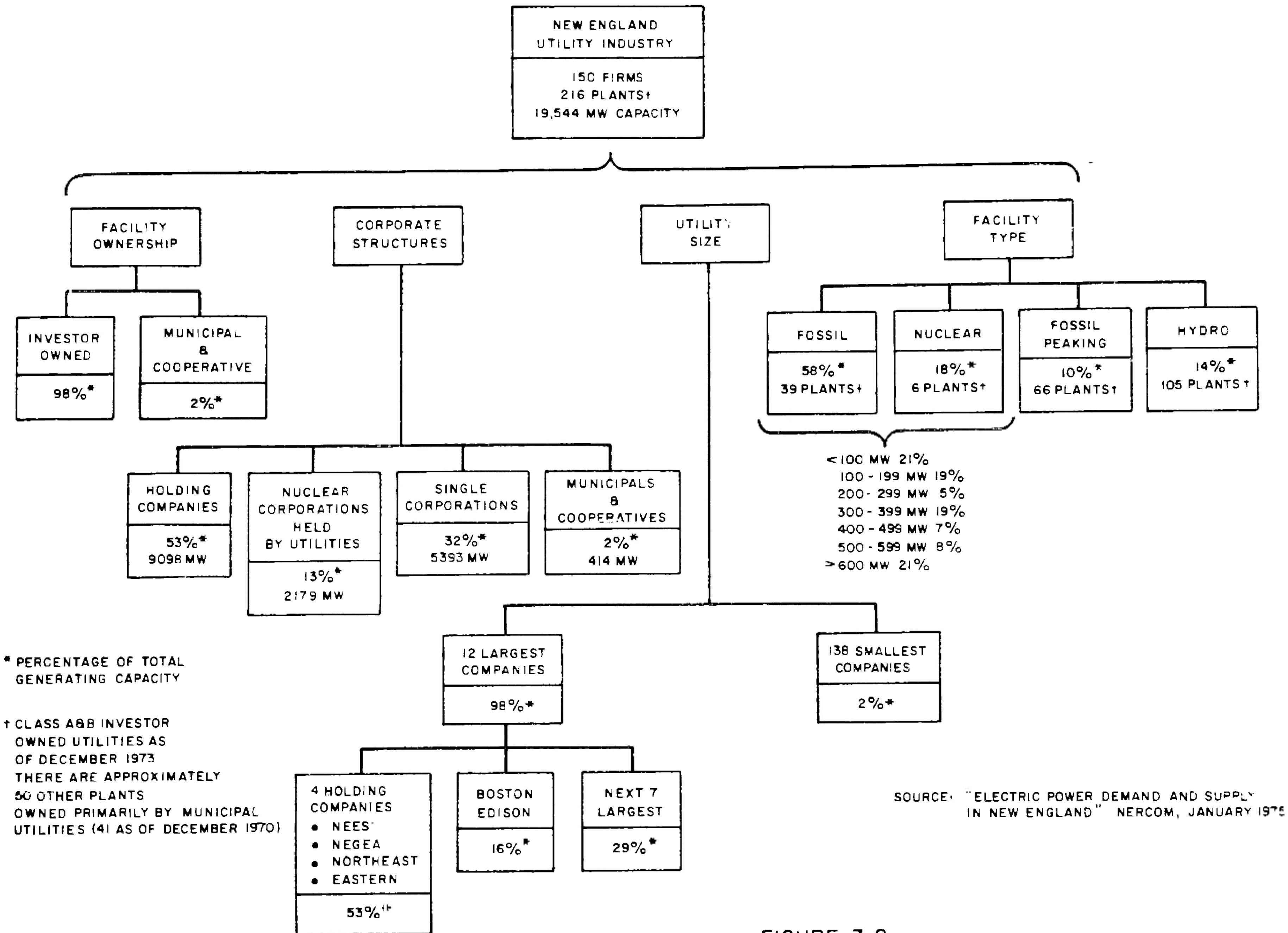
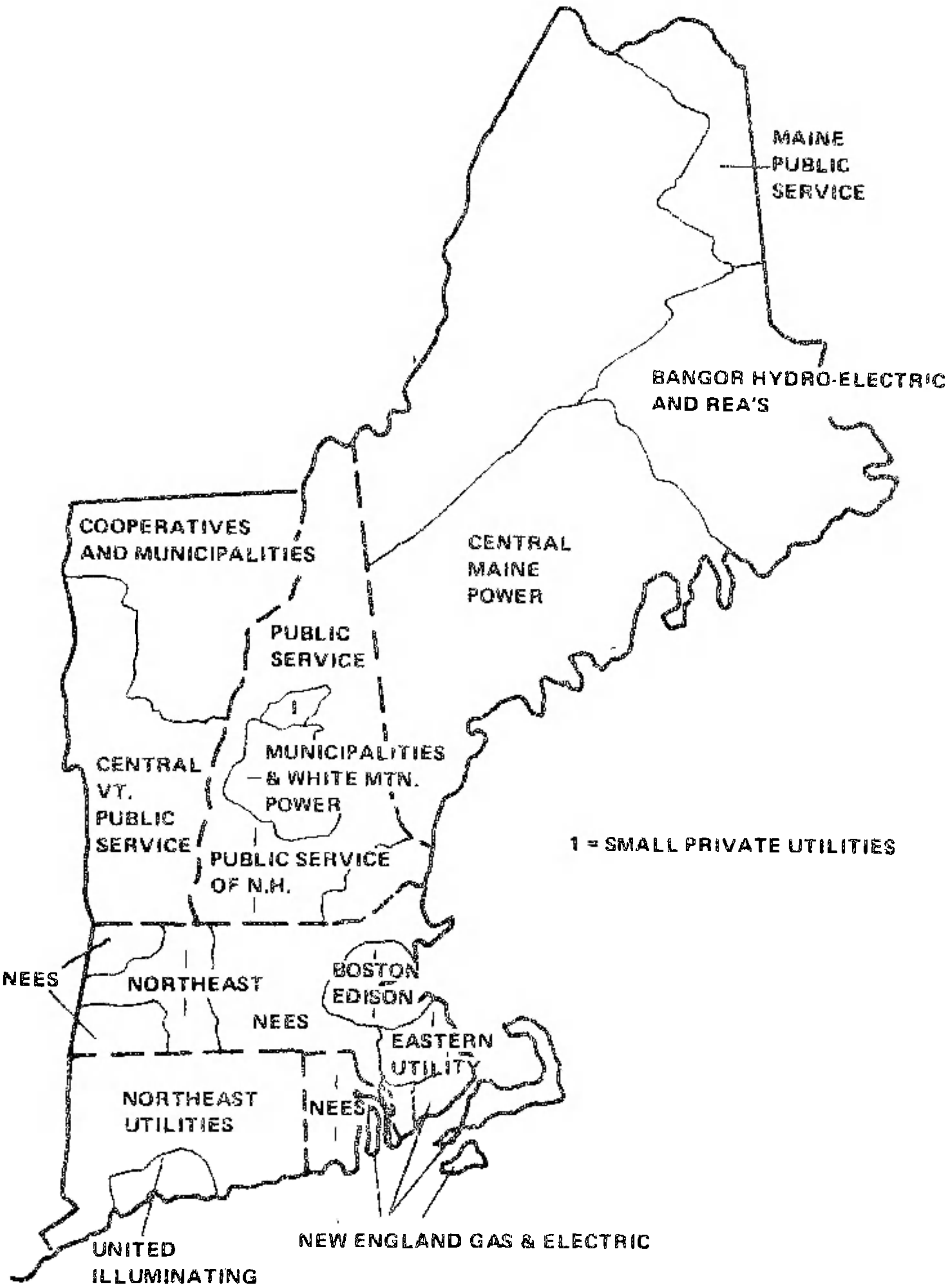



FIGURE 3.2
STRUCTURE OF THE NEW ENGLAND UTILITY INDUSTRY




Source: A study of the Electric Power Situation in New England 1970-1990, New England Regional Commission.

FIGURE 3.[illegible]

[illegible] SERVICE [illegible]EAS [illegible]

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system demand. Similarly, although there are a large number of individual firms, the system is dominated by the twelve largest companies.

A massive coordinating effort provides the region with a reliable supply of electric power; the New England power industry recognized that it was not economically possible for each company to meet its own needs on an isolated basis. To provide an integrated power system, the industry formed the New England Power Pool (NEPOOL) in 1966.[1] Originally it was sponsored by the nine largest private utilities. However, the doors have since been opened to all New England utilities, both public and private.

There are essentially two arms to NEPOOL:

(a) New England Power Exchange (NEPEX), responsible for centralized dispatch of power (i.e. coordinated operation of all utilities with, in effect, a pooling of generation and transmission facilities);

(b) New England Power Planning (NEPLAN), responsible for both forecasting the total demand for the region and defining the growth in total generating capacity.

NEPOOL is a continuing venture that produces electric load forecasts annually, the latest one in January 1976.

Another organization, the New England Energy Policy Staff (NEEPS) was formed in 1970 by the New England Regional Commission (NERCOM). NEEPS' task was to study regional energy requirements and develop an electric load forecast independent of the utilities. Their report was published in July 1973,[2] and the organization was then dissolved.

Other organizations such as the Northeast Power Coordinating Council (NPCC), the Electric Council of New England, and the Federal Power Commission all have an interest in utility operations in New England. However, none of these organizations prepares an independent load forecast for the region.

Thus, there are only two independent forecasts available and only the NEPOOL forecast is up to date.

### 3.03.2 - Demand Patterns in New England

New England is a distinct region -- in its geography, its cultures, and its economy. It has no indigenous energy resources (except hydro) and few of the minerals essential to modern industry. Although it is a comparatively small region (about 66,000 square miles), it is the size of a modern regional power system*. However, much of the population and industry is concentrated in the southern half of the region.

Because of the lack of natural resources in New England, its cost of electricity has been somewhat higher than elsewhere in the U. S. Nevertheless, throughout the 1950's and 1960's the cost of electricity consistently decreased. The average price of a kwh of electricity fell from 3.6 cents in 1950 to 2.6 cents in 1970,[3] which represented a relatively cheap form of energy. Thus, it is not surprising that the annual growth rate for electrical energy usage far outstretched the region's annual growth rate of overall energy usage during this period.

However, the advent of the 1970's has seen a reversal of conditions. The cost of electricity in New England (and elsewhere) has jumped sharply. This has been caused by a number of factors acting simultaneously. These include a dramatic increase in the price of oil (upon which New England relies heavily), increased environmental constraints, and somewhat depressed economic conditions -- all contributing to a decrease in the rate of growth of consumption.

(a) Historical Trends in Growth

Historical trends in growth of electric power demand and energy consumption was traditionally the basis of projection of demand by many utilities prior to 1970.[1] Load forecasts made on the basis of such trends were until that year reasonably reliable. However, since 1970 a number of uncertainties have entered into the picture.

The situation was made even more unstable by the Arab oil embargo of 1973/74. A number

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* The areas served by Tennessee Valley Authority and American Electric Power are about 80,000 and 41,000 square miles respectively.

of previously unimportant factors have now begun to influence demand in a manner most difficult or impossible to predict with any certainty:

- Increasing scarcity and consequently greater cost of traditional energy sources;

- Delays in implementation and increasing costs of power developments arising from public concern for preservation of the environment;

- Coincident recessionary and inflationary trends in the U. S. economy (although indications are now that the recession is over);

- Greater emphasis on energy conservation in all sectors of the economy.

(b) Growth in Peak Demand

The coincident system peak load in New England has generally occurred in winter, and since 1971/72 has shifted from a December to a January peak. However, the increased use of air conditioning has caused a much more rapid increase in summer (August) peak than in the winter value. In fact, in 1973 the August peak of 13,079 MW was 1.3 percent greater than the 12908 MW January peak of the subsequent relatively mild winter of 1973/74. The 1975 August peak of 12842 MW was on the other hand 7.7 percent less than the January 1976 peak of 13903 MW, and still 2 percent less than the August 1973 peak.[4]

Electric home heating in winter and air conditioning in summer are the main factors influencing the system peak loads. Summer and winter weather sensitive loads were reported in 1975 to represent about 27 percent of the total New England load, and to be increasing at about 20 percent per annum compared to only a 3 to 5 percent growth rate for non-weather sensitive load.

Figure 3.4 shows the growth in system peak load since 1965/66 from a winter coincident peak of 6,640 MW to 13,543 MW in 1972/73[4]. This is equivalent to a compound annual growth rate of approximately 7.6 percent. A sharp decline in

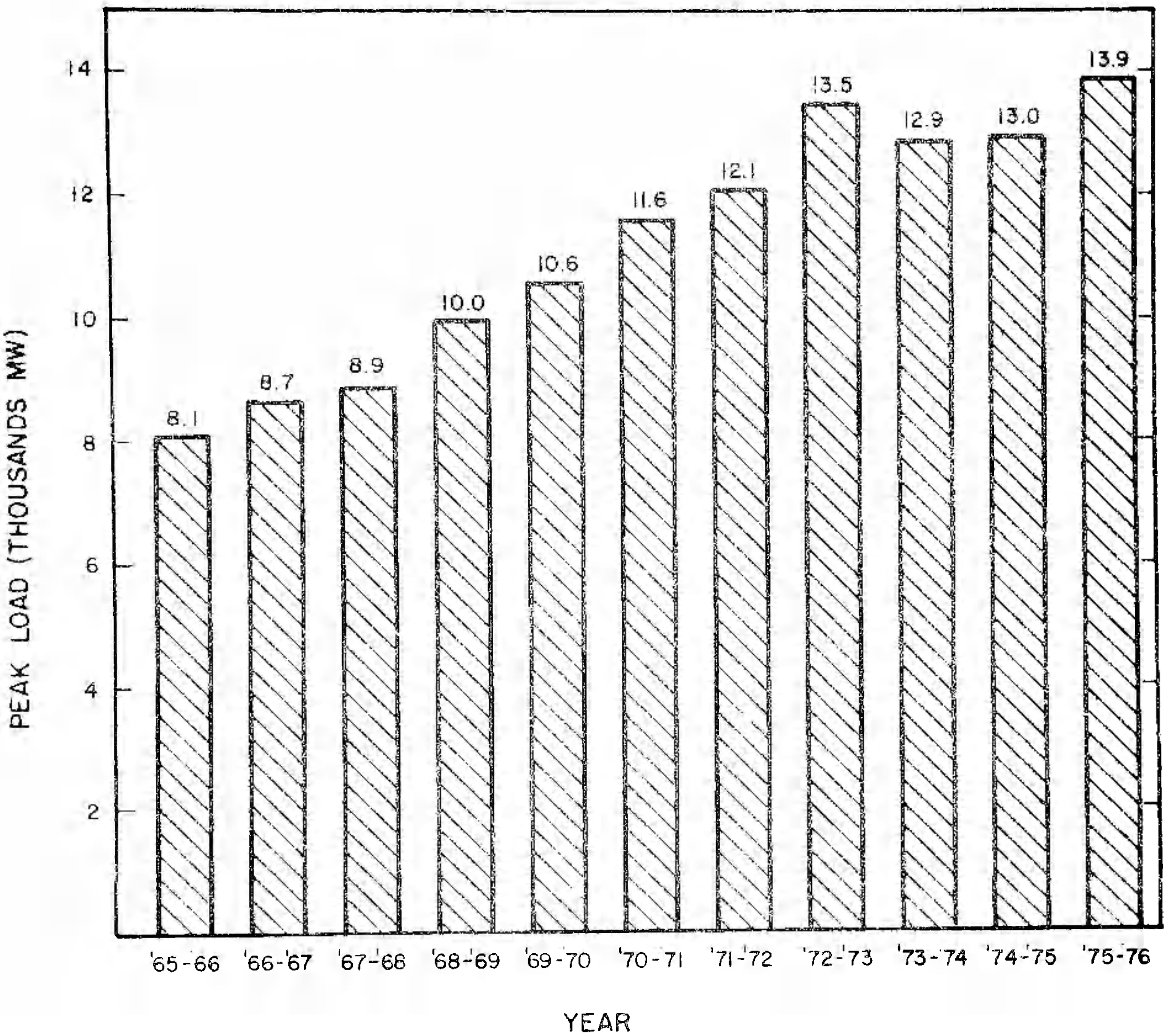



FIGURE 3.4
TREND IN WINTER PEAK IN
NEW ENGLAND

the peak to 12,908 MW occurred in the winter of 1973/74. This is attributed to the effect of conservation combined with the Arab oil embargo of 1973 and the relatively mild winter of 1973/74[1]. A gradual recovery followed in the two succeeding winters to 13,027 MW in January 1975 and 13,908 MW in January 1976, or nearly 3 percent more than the 1972/73 winter peak. In the two years since January 1974, the winter peak has thus grown at an approximate average annual compound rate of 3.8 percent.

(c) Growth in Energy Consumption

Total system annual energy sales to consumers have grown from 34,207 GWh in 1964 to 68,364 GWh in 1973, an average annual compound growth rate of approximately 8 percent (Table 3.1)[3]. In 1974 energy sales fell to 66,894 GWh, or about 2 percent, in line with the decline in peak load in the winter of 1973/74. No data is yet available for 1975, but earlier trends in growth of load factor and the recent trend in increased winter peak would indicate a return to a positive growth rate in energy consumption. Actual energy generation exceeded sales by about 12 percent annually, allowing for losses and unmetered quantities.

Average annual load factors based on annual coincident peak load and net energy consumption rose from 58.6 percent in 1964 to 64.2 percent in 1973 (Figure 3.5)[4]. The generally increasing trend is attributed to the increased use of air conditioning and the partially successful endeavor of utilities to promote off-peak consumption on both a daily and seasonal basis[1].

(d) Geographic Distribution

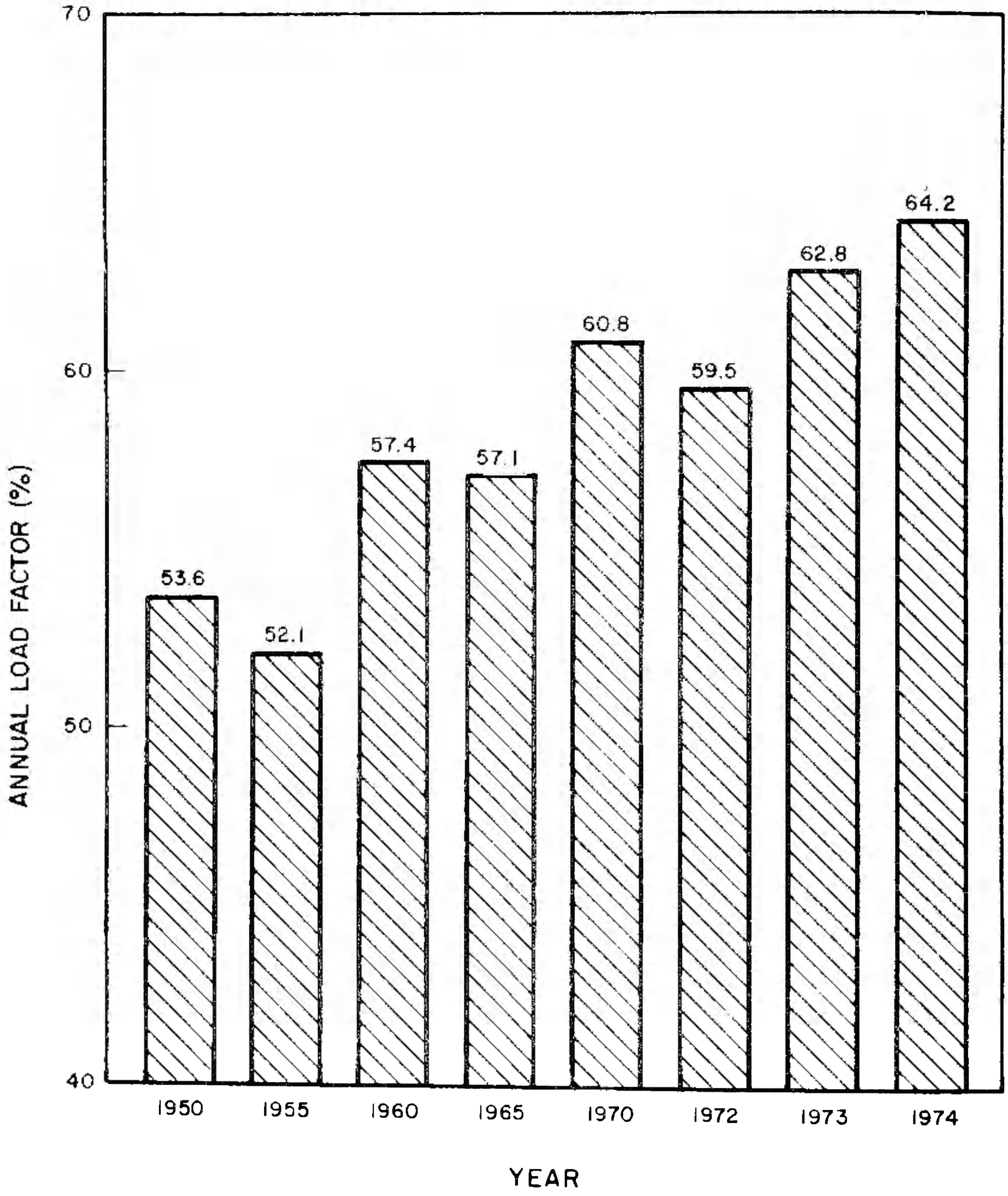
Massachusetts and Connecticut have long accounted for the major portion of electrical energy consumption in New England, amounting to about 72 percent in 1974 (Table 3.1). From 1964 to 1973 energy sales in these two States increased by an average 7.8 percent per annum. In line with the general trend in the New England region, energy sales in these two states in 1974 were down about 2.8 percent. Massachusetts and

TABLE 3.2

ELECTRIC POWER CONSUMPTION BY CUSTOMER CLASS IN THE SIX NEW ENGLAND STATES FOR 1964, 1973, AND 1974

| Year | State | Total Million kWh | Residential Million kWh | Residential % | Commercial Million kWh | Commercial % | Industrial Million kWh | Industrial % | Street Lighting Million kWh | Street Lighting % | Other Million kWh | Other % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1964 | Maine | 3,181 | 1,130 | 35.5 | 472 | 14.8 | 1,337 | 42.1 | 35 | 1.1 | 207 | 6.5 |
| | New Hampshire | 2,086 | 791 | 37.9 | 303 | 14.5 | 825 | 39.6 | 25 | 1.2 | 142 | 6.8 |
| | Vermont | 1,336 | 581 | 43.5 | 309 | 23.2 | 396 | 29.6 | 15 | 1.1 | 35 | 2.6 |
| | Massachusetts | 15,253 | 5,109 | 33.5 | 3,718 | 24.4 | 5,900 | 38.6 | 256 | 1.7 | 270 | 1.8 |
| | Rhode Island | 2,481 | 802 | 32.3 | 380 | 15.3 | 1,155 | 46.6 | 41 | 1.7 | 103 | 4.1 |
| | Connecticut | 9,870 | 3,600 | 36.5 | 2,428 | 24.6 | 3,666 | 37.1 | 156 | 1.6 | 20 | 0.2 |
| | New England Total | 31,207 | 12,013 | 35.1 | 7,610 | 22.2 | 13,279 | 38.8 | 528 | 1.6 | 777 | 2.3 |
| 1973 | Maine | 5,995 | 2,265 | 37.8 | 1,284 | 21.4 | 2,205 | 36.8 | 58 | 1.0 | 183 | 3.0 |
| | New Hampshire | 4,864 | 2,060 | 42.4 | 820 | 16.9 | 1,915 | 39.4 | 36 | 0.7 | 33 | 0.6 |
| | Vermont | 3,148 | 1,490 | 47.3 | 576 | 18.3 | 897 | 28.5 | 19 | 0.6 | 166 | 5.3 |
| | Massachusetts | 30,216 | 11,142 | 36.9 | 9,582 | 31.7 | 8,684 | 28.8 | 310 | 1.0 | 498 | 1.6 |
| | Rhode Island | 4,822 | 1,693 | 35.1 | 1,466 | 30.4 | 1,474 | 30.6 | 61 | 1.3 | 128 | 2.6 |
| | Connecticut | 19,319 | 7,519 | 38.9 | 5,696 | 29.5 | 5,862 | 30.4 | 216 | 1.1 | 26 | 0.1 |
| | New England Total | 68,364 | 26,169 | 38.3 | 19,424 | 28.4 | 21,037 | 30.8 | 700 | 1.0 | 1,034 | 1.5 |
| 1974 | Maine | 6232 | 2405 | 38.6 | 1287 | 20.6 | 2317 | 37.2 | 60 | 1.0 | 163 | 2.6 |
| | N.Hamp. | 4860 | 2112 | 43.5 | 813 | 16.7 | 1867 | 38.4 | 36 | 0.7 | 32 | 0.7 |
| | Vermont | 3095 | 1486 | 48.0 | 553 | 17.9 | 884 | 28.6 | 19 | 0.6 | 153 | 4.9 |
| | Mass. | 29356 | 10974 | 37.4 | 9420 | 32.1 | 8176 | 27.8 | 315 | 1.1 | 471 | 1.6 |
| | Rhode Isl. | 4551 | 1642 | 36.1 | 1359 | 29.9 | 1421 | 31.2 | 59 | 1.3 | 70 | 1.5 |
| | Conn. | 18800 | 7475 | 39.8 | 5472 | 29.1 | 5611 | 29.8 | 217 | 1.2 | 25 | 0.1 |
| | N.England Total | 66894 | 26094 | 39.0 | 18904 | 28.3 | 20276 | 30.3 | 706 | 1.0 | 914 | 1.4 |

Source: "Electric Utility Industry in New England Statistical Bulletin 1973 - 1974", Electric Council of New England.




SOURCE: ELECTRIC UTILITY INDUSTRY IN NEW ENGLAND - STATISTICAL BULLETIN, 1974

FIGURE 3.5

TREND IN ANNUAL LOAD FACTOR IN NEW ENGLAND

Connecticut are relatively more industrialized and populated than the remaining states which in general tend to be more rural in nature. In contrast, energy sales in these four states rose 8.4 percent from 1964 to 1973 and fell only 0.5 percent from 1973 to 1974.

(e) Sectoral Distribution

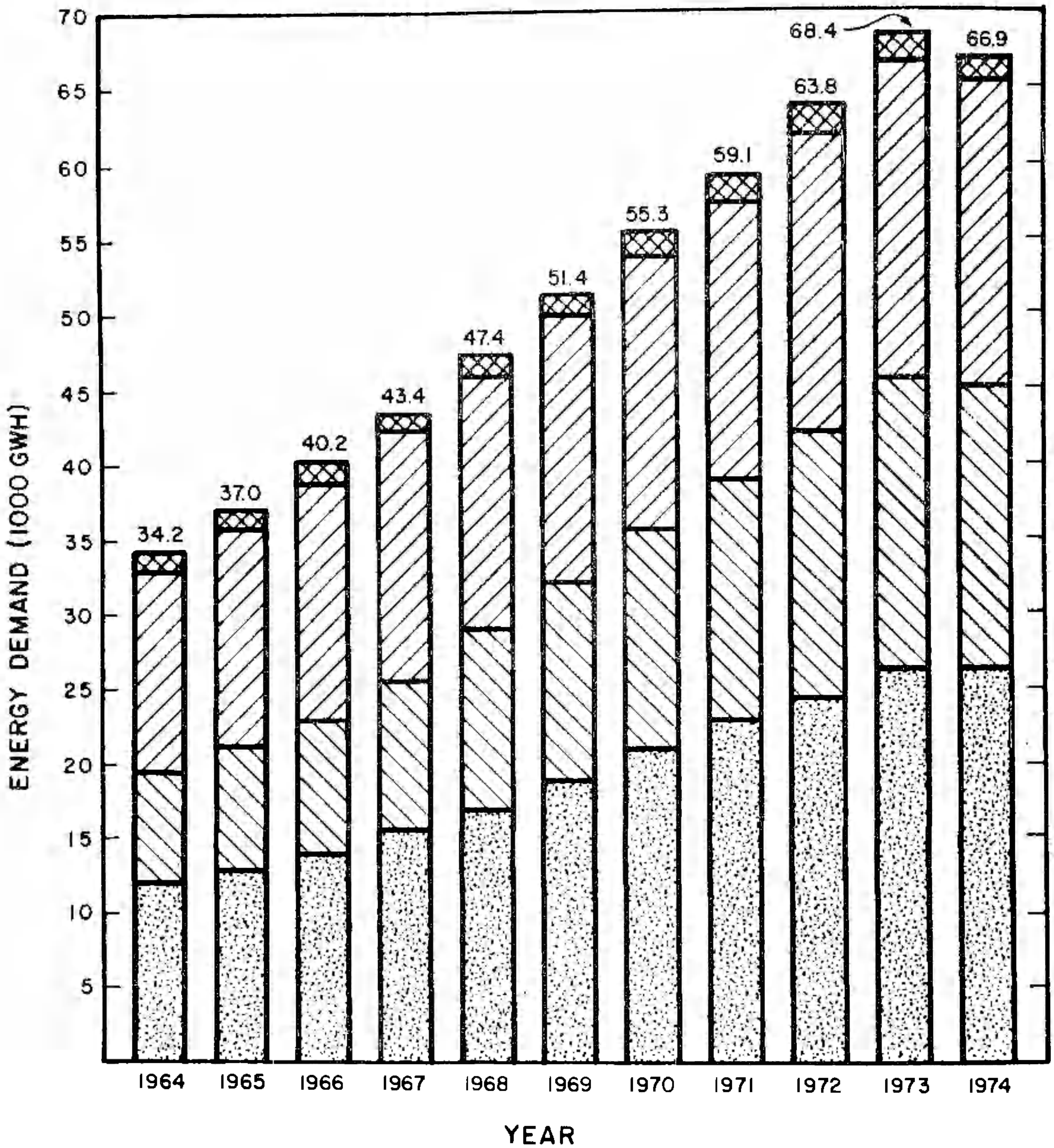
Figure 3.6 shows the growth in energy sales in the six New England States from 1964 to 1974 in terms of the residential, commercial, industrial, and other sectors[3]. The proportion of consumption in the residential and commercial sectors has continued to expand, and in 1974 accounted for more than 67 percent of the total. Annual growth rates to 1973 averaged 9 percent for residential and 11 percent for commercial, compared with less than 5 percent in the industrial sector, a strong indication of the general shift in the economy from an industrial to a commercial base. In 1974 residential and commercial sales were down 0.3 percent and 2.7 percent respectively from 1973 while industrial demand fell 3.6 percent.

### 3.03.3 - Existing Forecasts

From the previous discussion of historical trends, it is evident that the 1970's have deviated substantially from historical patterns. This necessitates a re-evaluation of forecasting procedures in light of greater uncertainty.

Each utility in New England currently produces a load forecast. All these individual forecasts are reviewed and consolidated by NEPOOL which then produces a final forecast for all of New England. The individual utilities generally prepare forecasts every six months for peak loads and energy demand for a period ahead of ten years. The NEPOOL forecast deals only with peak load since this is the basis for planning future generation capability. NEPOOL also produces annual 20-year forecasts of peak load based on projections from the 10-year forecast.

The only other forecast for the region was made by NEEPS in 1973. This forecasted peak loads and energy




LEGEND

RESIDENTIAL

COMMERCIAL

INDUSTRIAL

OTHER

SOURCE: ELECTRIC UTILITY INDUSTRY IN NEW ENGLAND – STATISTICAL BULLETIN, 1974

FIGURE 3.6

TREND IN ENERGY DEMAND IN NEW ENGLAND

through the year 2000. An extensive review of the NEEPS (July 1973) and NEPOOL (October 1974) forecasts was made by the New England Regional Commission in a report published in January 1975[1]. The latest available ten-year NEPOOL forecast for 1975-1986 was published in January 1976[4]. A further NEPOOL forecast to 2000/2001 was published in March 1976. Each of the forecasts will be discussed in turn.

(a) <u>New England Energy Policy Staff (NEEPS)</u>

The New England Energy Policy Staff was established by NERCOM in 1970. Its task was to study New England's total energy requirements[7].

The forecast was essentially based on estimates of future energy consumption on a sectoral basis with an allowance for losses, etc. based on historical trends. Peak loads were then estimated on the basis of historical load factors adjusted to take account of sectoral trends. Three major sectors were identified:

- Residential (based on consumption per customer and the number of customers);
- Commercial (based on consumption per household and the number of households);
- Industrial (based on per capita consumption and the population).

The estimates of peak load growth are indicated in Table 3.3. These estimates, however, were made just before the slump in electrical consumption occurred in 1973/74. As a result, even the short-term forecasts did not materialize in reality, and the long-term forecasts are now considered to be too high. Accordingly, the NEEPS forecast will not be included in present forecasts. However, it is interesting to compare the NEEPS forecast with the 1972 NEPOOL forecast (Table 3.4). This shows that both organizations projected almost identical loads at that time[1].

TABLE 3.3

NEW ENGLAND ELECTRICAL DEMAND
AND GENERATION FORECAST (NEEPS, 1973)

| Power Year Demands | | | | Calendar Year Generation | | |
|---|---|---|---|---|---|---|
| Power Year | December Peak MW | January Peak MW | Summer Peak | Year | Total Requirements MWH x $10^3$ | Annual* Load Factor |
| 1972-73 | | | 12585 | | | |
| 1973-74 | 14075 | 14197 | 13500 | 1973 | 76860 | 62.3 |
| 1974-75 | 15182 | 15340 | 14496 | 1974 | 82787 | 62.2 |
| 1975-76 | 16369 | 16562 | 15577 | 1975 | 89169 | 62.2 |
| 1976-77 | 17647 | 17874 | 16746 | 1976 | 96048 | 62.1 |
| 1977-78 | 19011 | 19270 | 18005 | 1977 | 103410 | 62.1 |
| 1978-79 | 20482 | 20772 | 19370 | 1978 | 111360 | 62.1 |
| 1979-80 | 22059 | 22379 | 20844 | 1979 | 119906 | 62.0 |
| 1980-81 | 23746 | 24092 | 22432 | 1980 | 129064 | 62.0 |
| 1981-82 | 25510 | 25881 | 24099 | 1981 | 138650 | 62.0 |
| 1982-83 | 27383 | 27778 | 25878 | 1982 | 148849 | 62.1 |
| 1983-84 | 29382 | 29798 | 27786 | 1983 | 159747 | 62.1 |
| 1984-85 | 31500 | 31935 | 29815 | 1984 | 171308 | 62.1 |
| 1985-86 | 33751 | 34204 | 31980 | 1985 | 183613 | 62.1 |
| 1986-87 | 36108 | 36576 | 34253 | 1986 | 196505 | 62.1 |
| 1987-88 | 38555 | 39037 | 36617 | 1987 | 209898 | 62.1 |
| 1988-89 | 41064 | 41560 | 39043 | 1988 | 223633 | 62.2 |
| 1989-90 | 43613 | 44124 | 41506 | 1989 | 237584 | 62.2 |
| 1990-91 | 46072 | 46600 | 43875 | 1990 | 251033 | 62.2 |
| 1991-92 | 48288 | 48819 | 46039 | 1991 | 263198 | 62.2 |
| 1992-93 | 50446 | 50981 | 48143 | 1992 | 275045 | 62.2 |
| 1993-94 | 52552 | 53094 | 50194 | 1993 | 286600 | 62.3 |
| 1994-95 | 54613 | 55165 | 52192 | 1994 | 297893 | 62.3 |
| 1995-96 | 56631 | 57193 | 54145 | 1995 | 308943 | 62.3 |
| 1996-97 | 58633 | 59205 | 56081 | 1996 | 319903 | 62.3 |
| 1997-98 | 60636 | 61220 | 58016 | 1997 | 330866 | 62.3 |
| 1998-99 | 62645 | 63242 | 59955 | 1998 | 341856 | 62.3 |
| 1999-2000 | 64652 | 65262 | 61888 | 1999 | 352829 | 62.3 |
| 2000 | 66641 | | | 2000 | 363704 | 62.3 |

* Based on December Peak Demand

Source: "Energy in New England - 1973 to 2000", NEEPS, July 1973.

TABLE 3.4

NEW ENGLAND POWER POOL
LOAD, ENERGY, AND CAPABILITY
FORECAST: 1973 - 1993

| | SUMMER | | WINTER | | ANNUAL |
|---|---|---|---|---|---|
| YEAR | LOAD MW | CAPABILITY MW | LOAD MW | CAPABILITY MW | NET ENERGY GWH |
| 1973 | 12804 | 17306 | 14406 | 18014 | 76054 |
| 1974 | 13810 | 18290 | 15554 | 20472 | 82197 |
| 1975 | 14908 | 21247 | 16731 | 21933 | 88695 |
| 1976 | 16057 | 21767 | 17965 | 22357 | 95320 |
| 1977 | 17326 | 22043 | 19312 | 24483 | 102651 |
| 1978 | 18666 | 23805 | 20732 | 25667 | 110390 |
| 1979 | 20123 | 26139 | 22286 | 27967 | 118808 |
| 1980 | 21672 | 29349 | 23937 | 30031 | 127870 |
| 1981 | 23373 | 30485 | 25718 | 32316 | 137433 |
| 1982 | 25184 | 35673 | 27596 | 34357 | 147775 |
| 1983 | 27145 | 36286 | 29728 | 37006 | 158891 |
| 1984 | 29261 | 36285 | 31962 | 39966 | 168584 |
| 1985 | 31544 | 39045 | 34363 | 42966 | 178867 |
| 1986 | 34006 | 42005 | 36945 | 46466 | 189773 |
| 1987 | 36659 | 45505 | 39721 | 49666 | 201354 |
| 1988 | 39519 | 48680 | 42705 | 53416 | 213637 |
| 1989 | 42604 | 52430 | 45914 | 57416 | 226669 |
| 1990 | 45928 | 56310 | 49363 | 61726 | 240496 |
| 1991 | 49512 | 60550 | 53072 | 66326 | 255166 |
| 1992 | 53375 | 64985 | 57060 | 71326 | 270731 |
| 1993 | 57540 | 69815 | 61347 | 76776 | 287241 |

Source: Preliminary NEPOOL Planning Data - Spring 1973

(b) New England Power Pool (NEPOOL)

The New England Power Pool (NEPOOL) is an organization composed of all the electric utilities in New England. The current NEPOOL forecasting procedure essentially involves summing individual utility peak load forecasts. A factor is then added for line losses and a diversity factor applied to allow for non-coincident peak loads between utilities[4]. Thus, the accuracy of NEPOOL's forecast is entirely dependent upon that of the individual utilities.

The shortcomings of this approach in the present climate of uncertainty in the power industry has led NEPOOL to investigate alternate methods of forecasting. A total econometric model for the whole New England area is now being developed.

The NEPOOL 10-year forecast is currently predicting an average winter peak load growth of 5.5 percent compounded annually through 1986/87 (Table 3.5). A similar growth rate is predicted for the summer peak. This contrasts with the historic trend from 1964 to 1973 which had average annual growth rates of 7.4 percent (winter) and 8.9 percent (summer).

For long range planning, the NEPOOL forecast through 2000/2001 shows average annual growth rates of 6.4 percent in winter and 6.3 percent in summer (Table 3.6).

(c) Constituent Utilities

The major utilities and power supply groups in the New England area and their January 1976 peak loads are:

TABLE 3.5

NEW ENGLAND POWER POOL SYSTEM LOAD
FORECASTS - 1976 THROUGH 1986/87

| | PEAK LOADS (MW) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | J | F | M | A | M | J | J | A | S | O | N | D | Energy (GWh) | Load Factor Percent |
| 1975 | | | | | | | | 12842* | | | | 13529* | | |
| 1976 | 13908* | 13056 | 12225 | 11998 | 11395 | 12542 | 13100 | 13369 | 12876 | 12459 | 13267 | 14492 | 77,096 | 60.6 |
| 1977 | 14518 | 13790 | 12917 | 12664 | 12017 | 13240 | 13811 | 14102 | 13580 | 13144 | 13991 | 15297 | 81,632 | 60.8 |
| 1978 | | | | | | | | 14829 | | | | | 86,069 | 60.8 |
| 1979 | 16159 | | | | | | | 15697 | | | | | 91,148 | 60.8 |
| 1980 | 17107 | | | | | | | 16633 | | | | | 96,581 | 60.8 |
| 1981 | 18129 | | | | | | | 17602 | | | | | 102,183 | 60.8 |
| 1982 | 19191 | | | | | | | 18589 | | | | | 107,884 | 60.8 |
| 1983 | 20249 | | | | | | | 19626 | | | | | 113,790 | 60.8 |
| 1984 | 21369 | | | | | | | 20740 | | | | | 120,361 | 60.8 |
| 1985 | 22578 | | | | | | | 21902 | | | | | 127,094 | 60.8 |
| 1986 | 23831 | | | | | | | 23085 | | | | | 133,695 | 60.8 |
| 1987 | 25105 | | | | | | | | | | | | | |
| Mean Annual Growth | 5.51% | | | | | | | 5.47% | | | | | | |

*Actual Loads

Source: New England Load and Capacity Report, 1975-1986, NEPLAN, January 1, 1976.

## TABLE 3.6 - TOTAL NEW ENGLAND FORECAST OF PERIOD PEAK LOADS

| POWER YEAR | Dec. 1 | Jan. 2 | Feb. 3 | Mar. 4 | Arp. 5 | May 6 | Jun. 7 | -- 8 | Jul. 9 | Aug. 10 | Sep. 11 | Oct. 12 | Nov. 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1976/77 | 14492 | 14518 | 13790 | 12917 | 12664 | 12017 | 13240 | 12960 | 13811 | 14102 | 13580 | 12263 | 13991 |
| 1977/78 | 15297 | 15317 | 14551 | 13632 | 13356 | 12682 | 13924 | 13628 | 14518 | 14329 | 14230 | 12943 | 14766 |
| 1978/79 | 16127 | 16159 | 15351 | 14382 | 14091 | 13380 | 14739 | 14426 | 15367 | 15697 | 15116 | 13654 | 15577 |
| 1979/80 | 17073 | 17107 | 16252 | 15225 | 14917 | 14165 | 15618 | 15286 | 16284 | 16633 | 16018 | 14455 | 16491 |
| 1980/81 | 18093 | 18129 | 17223 | 16135 | 15808 | 15011 | 16528 | 16176 | 17232 | 17602 | 16951 | 15319 | 17476 |
| 1981/82 | 19153 | 19191 | 18231 | 17080 | 16735 | 15890 | 17455 | 17083 | 18199 | 18589 | 17901 | 16216 | 18500 |
| 1982/83 | 20209 | 20249 | 19237 | 18022 | 17657 | 16766 | 18429 | 18036 | 19214 | 19626 | 18900 | 17110 | 19520 |
| 1983/84 | 21326 | 21369 | 20301 | 19018 | 18634 | 17694 | 19475 | 19060 | 20304 | 20740 | 19973 | 18057 | 20600 |
| 1984/85 | 22533 | 22578 | 21449 | 20094 | 19688 | 18695 | 20566 | 20128 | 21442 | 21902 | 21092 | 19078 | 21765 |
| 1985/86 | 23783 | 23831 | 22639 | 21210 | 20781 | 19732 | 21677 | 21215 | 22600 | 23085 | 22231 | 20137 | 22973 |
| 1986/87 | 25055 | 25105 | 23850 | 22343 | 21892 | 20787 | 22891 | 22403 | 23866 | 24378 | 23476 | 21214 | 24202 |
| 1987/88 | 26458 | 26511 | 25185 | 23595 | 23118 | 21951 | 24173 | 23658 | 25202 | 25743 | 24791 | 22499 | 25557 |
| 1988/89 | 27899 | 27955 | 26557 | 24880 | 24377 | 23147 | 25527 | 24983 | 26614 | 27185 | 26179 | 23622 | 26949 |
| 1989/90 | 29504 | 29563 | 28085 | 26311 | 25779 | 24478 | 26956 | 26382 | 28104 | 28707 | 27645 | 24981 | 28499 |
| 1990/91 | 31157 | 31219 | 29658 | 27785 | 27223 | 25849 | 28465 | 27859 | 29677 | 30314 | 29192 | 26380 | 30095 |
| 1991/92 | 32901 | 32967 | 31319 | 29341 | 28747 | 27297 | 30059 | 29419 | 31340 | 32012 | 30826 | 27857 | 31780 |
| 1992/93 | 34743 | 34813 | 33072 | 30984 | 30357 | 28825 | 31742 | 31066 | 33094 | 33804 | 32553 | 29417 | 33560 |
| 1993/94 | 36689 | 36763 | 34925 | 32719 | 32057 | 30440 | 33520 | 32806 | 34948 | 35698 | 34377 | 31065 | 35440 |
| 1994/95 | 38743 | 38821 | 36880 | 34551 | 33852 | 32144 | 35397 | 34644 | 36905 | 37697 | 36302 | 32804 | 37423 |
| 1995/96 | 40873 | 40955 | 38907 | 36450 | 35713 | 33911 | 37379 | 36583 | 38971 | 39807 | 38304 | 34607 | 39481 |
| 1996/97 | 43204 | 43291 | 41126 | 38529 | 37750 | 35845 | 39473 | 38632 | 41154 | 42037 | 40482 | 36561 | 41733 |
| 1997/98 | 45624 | 45715 | 43429 | 40686 | 39863 | 37852 | 41683 | 40795 | 43459 | 44391 | 42749 | 38639 | 44069 |
| 1998/99 | 48179 | 48276 | 45862 | 42966 | 42097 | 39973 | 44017 | 43079 | 45892 | 46876 | 45142 | 40798 | 46538 |
| 1999/2000 | 50877 | 50979 | 48430 | 45371 | 44454 | 42211 | 46482 | 45492 | 48462 | 49502 | 47679 | 43077 | 49144 |
| 2000/2001 | 53726 | 53834 | 51142 | 47912 | 46943 | 44575 | 49085 | 48040 | 51176 | 52274 | 50340 | 45490 | 51896 |
| Avg. Annual Growth: | | 5.6% | | | | | | | | 5.6% | | | |

**SOURCE:** Winter and summer peak loads through 1987 were taken from the January 1976 New England Load and Capacity Report. All other data developed by NEPLAN based on Load Forecasting Task Force Case 2cc (i.e. 5.6% annual growth rate for both weather and non-weather sensitive load components -- fixed load shape).

| | MW | Percent |
|---|---|---|
| Northeast Utilities | 3540 | 25.4 |
| New England Electric System | 2796 | 20.1 |
| Boston Edison | 1723 | 12.4 |
| Public Service Co. of New Hampshire | 1030 | 7.4 |
| Central Maine Power Co. | 956 | 6.9 |
| United Illuminating Co. | 792 | 5.7 |
| New England Gas and Electric Assoc. | 529 | 3.8 |
| Central Vermont Public Service Corporation | 356 | 2.6 |
| Municipals | 743 | 5.3 |
| Others | 1373 | 9.9 |
| Total all Utilities | 13838 | |
| 345 kv losses | 70 | 0.5 |
| Total Coincident Load | 13908 | 100.0 |

To better assess the validity of the NEPOOL forecast, the forecasting procedures used by the individual utilities should be reviewed. Because of the number of utilities, it would be impractical to review them all.

With the exception of NEGEA, the municipals and others, the procedures of the individual utilities are reviewed in Section 3.03.4.

## 3.03.4 - Forecasting Procedures of Major Utilities

The procedures used by Northeast Utilities, New England Electric System, Boston Edison, Public Service Company of New Hampshire, Central Maine Power Company, United Illuminating Company, and Central Vermont Public Service Corporation are reviewed in this section.

(a) The Northeast Utilities System

The Northeast Utilities system consists of five companies serving some of the more densely populated areas of southern New England:

- Connecticut Light and Power Company
- Hartford Electric Light Company
- Western Massachusetts Electric Company
- Holyoke Water Power Company
- Northeast Nuclear Energy Company

All these companies are wholly owned subsidiaries of Northeast Utilities, a public utility holding company.

The Northeast Utilities System produces a comprehensive 10-year forecast and also a 20-year projection[6]. The forecast is performed on a sectoral basis for both energy and peak load. The market sectors considered are:

- Residential
- Commercial
- Industrial
- Street Lighting
- Railroad
- Wholesale.

- Residential energy forecasts are based on a 1.8 percent forecast population growth through 1985 and a 1.9 percent growth in average use per customer. The resulting net growth in residential consumption is 3.8 percent. Residential usage accounted for 37.5 percent of consumption in the NUS area in 1974 which is comparable with the proportion for the whole of Massachusetts and Connecticut (Table 3.2). This is expected to drop to 34.4 percent by 1985. The NUS forecast also includes an analysis of the effect of price on consumption.

- Commercial sector forecasts include schools, office buildings, retail establishments, etc.

The commercial sector in the NUS area comprised 26.3 percent of the total consumption in 1974. This is somewhat less than the average of about 31 percent for the entire Massachusetts/Connecticut region. This sector is expected to grow to 32.5 percent by 1985. An attempt is currently being made to develop a coding system for the diverse types of commercial users in the NUS area. However, there is insufficient historical data to produce accurate forecasts. Thus, the NUS forecast is based on Connecticut Energy Advisory Board projections which relate employment and energy consumption per employee.

The forecast growth rate is 6.5 percent through 1985.

- Industrial energy consumption in the NUS area is the most sensitive to fluctuations in the economy and has traditionally varied more significantly than in other sectors. In 1974 the NUS industrial sector comprised 26.7 percent of the system in terms of energy consumption, which is marginally less than the 28.6 percent proportion for the whole of Massachusetts and Connecticut. A decline to 24.0 percent is predicted by 1985.

  The NUS forecast for the industrial sector is based on 14 sub-categories of users, and through 1985 is estimated at a growth rate of 4.7 percent.

- Street lighting energy consumption is forecast at 2 percent growth. This is based on the historic growth rate since little indication of conservation has been observed.

- Railroad forecast energy consumption for 1985 is 0.7 percent of the total NUS area, based on estimates of Penn Central's modernization program.

- Wholesale forecasts for sales of bulk power to 16 municipally and privately owned electric systems are based on individual energy estimates from the users or by correlation with Northeast Utilities estimates. This sector is predicted to grow at 4.0 percent to a 7.7 percent proportion of the total system by 1985.

The total energy forecast for these sectors is indicated in Table 3.7, representing a compound annual growth rate of about 4.9 percent through 1985.

The second forecasting task was to estimate the annual peak demand. The annual peak has traditionally occurred in either December or January. Many factors influence the timing and level of the peak load including weather, economic conditions, and conservation efforts.

The system peak load was estimated on the basis of projected sector loads that occur at the time of system peak. The results of the analysis were a compound annual growth of the peak load of about 4.7 percent (see Table 3.7).

Because of major uncertainties existing in forecasting, Northeast Utilities did not attempt to forecast the 1986 to 1995 peak loads. Instead, they used a method to calculate the impact of probable events on a variable (such as population, transportation, electric heating, etc.). The purpose of the analysis is to establish a range of values, not a forecast suitable for planning new facilities.

The most likely peak loads for 1990 and 1995 are suggested as 7007 and 8647 MW, respectively. However, it is more appropriate to consider the probable high and low values. For 1995 these are 9163 MW and 8131 MW. From 1975 this represents a compounded annual growth rate of a low of 4.1 percent to a high of 4.7 percent with a mean value of 4.4 percent.

(b) New England Electric System (NEES)

The New England Electric System is a group of five companies serving most of Rhode Island, eastern Massachusetts (except Boston), and parts of western Massachusetts and southern New Hampshire. The companies include: Granite State Electric Co., Massachusetts Electric Co., the Narragansett Electric Co., New England Power Co., and New England Power Service Co.

Due to the uncertainties in the electric utility industry, NEES has chosen to adopt a "bandwidth" approach to planning. In its latest submission

TABLE 3.7

NORTHEAST UTILITIES SYSTEM
TOTAL ENERGY OUTPUT REQUIREMENTS[1]

FORECAST 1975-1985

Gigawatthours

| Year | Residential | Commercial | Industrial | Street Lighting | Railroad | Wholesale | Company Use[2] | Total Energy Output Requirements |
|---|---|---|---|---|---|---|---|---|
| 1975 | 7623 | 5527 | 4689 | 206 | - | 1556 | 42 | 19643 |
| 1976 | 7830 | 5836 | 4948 | 210 | - | 1648 | 42 | 20514 |
| 1977 | 8158 | 6214 | 5314 | 214 | - | 1766 | 43 | 21709 |
| 1978 | 8503 | 6617 | 5526 | 218 | 20 | 1858 | 43 | 22786 |
| 1979 | 8897 | 7046 | 5803 | 223 | 97 | 1950 | 44 | 24061 |
| 1980 | 9276 | 7503 | 6149 | 227 | 115 | 2025 | 44 | 25340 |
| 1981 | 9649 | 7990 | 6393 | 232 | 120 | 2111 | 45 | 26539 |
| 1982 | 9998 | 8509 | 6610 | 236 | 126 | 2202 | 45 | 27726 |
| 1983 | 10354 | 9061 | 6851 | 241 | 133 | 2096 | 45 | 28781 |
| 1984 | 10732 | 9649 | 7120 | 246 | 219 | 2197 | 46 | 30209 |
| 1985 | 11053 | 10275 | 7433 | 250 | 229 | 2302 | 46 | 31589 |
| Compound Rate Growth | 3.8% | 6.4% | 4.7% | 2.0% | - | 4.0% | 1.0% | 4.9% |

[1] Sales from Table I-21 adjusted to include losses as discussed in text.

[2] Sum of consumption in company office buildings and service facilities plus associated losses. Does not include generating station service.

Source: "Ten- and Twenty-Year Forecasts of Loads and Resources", p. 60, the Northeast Utilities System, January 1, 1976.

## TABLE 3.8 - NORTHEAST UTILITIES SYSTEM - PEAK LOADS AND TOTAL SYSTEM ENERGY OUTPUT REQUIREMENTS

ACTUAL 1969-1974
FORECAST 1975-1985

| Year | Total Output[1] GWH (1) | Annual Change % (2) | AM Peak[2] MW (3) | AM Load Factor[3] (4) | Annual Change % (5) | PM Peak[4] MW (6) | PM Load Factor[5] (7) | Annual Change % (8) | Summer Peak[6] MW (9) | Annual Change % (10) |
|---|---|---|---|---|---|---|---|---|---|---|
| ACTUAL | | | | | | | | | | |
| 1969 | 15773 | - | - | - | - | 3004 | .599 | - | 2665 | - |
| 1970 | 16950 | 7.5 | - | - | - | 3145 | .612 | - | 2823 | 5.9 |
| 1971 | 17653 | 4.2 | 3283 | .614 | - | - | - | - | 2988 | 5.8 |
| 1972 | 19204 | 8.8 | - | - | - | 3637 | .603 | - | 3166 | 6.0 |
| 1973 | 20126 | 4.8 | 3476 | .661 | - | - | - | - | 3562 | 12.5 |
| 1974 | 19616 | -2.2 | - | - | - | 3456 | .648 | - | 3296 | -7.5 |
| FORECAST | | | | | | | | | | |
| 1975 | 19643 | .1 | 3501 | .640 | 4.9 | 3659 | .613 | 5.9 | 3442[7] | 3.9 |
| 1976 | 20514 | 4.4 | 3656 | .641 | 4.4 | 3809 | .615 | 4.1 | 3622 | 5.2 |
| 1977 | 21709 | 5.8 | 3868 | .641 | 5.8 | 4017 | .617 | 5.5 | 3770 | 4.1 |
| 1978 | 22786 | 5.0 | 4062 | .640 | 5.0 | 4229 | .615 | 5.3 | 3977 | 5.5 |
| 1979 | 24061 | 5.6 | 4290 | .640 | 5.6 | 4449 | .617 | 5.2 | 4187 | 5.3 |
| 1980 | 25340 | 5.3 | 4520 | .640 | 5.4 | 4674 | .619 | 5.1 | 4405 | 5.2 |
| 1981 | 26539 | 4.7 | 4738 | .639 | 4.8 | 4889 | .620 | 4.6 | 4627 | 5.1 |
| 1982 | 27726 | 4.5 | 4954 | .639 | 4.6 | 5100 | .621 | 4.3 | 4840 | 4.6 |
| 1983 | 28781 | 3.8 | 5154 | .638 | 4.0 | 5299 | .620 | 3.9 | 5049 | 4.3 |
| 1984 | 30209 | 5.0 | 5417 | .637 | 5.1 | 5547 | .622 | 4.7 | 5246 | 3.9 |
| 1985 | 31589 | 4.6 | 5668 | .636 | 4.6 | 5784 | .623 | 4.3 | 5492 | 4.7 |
| Compound Growth Rate 1974-85 | 4.5% | | 4.8%[8] | | | 4.8% | | | 4.9% | |
| Compound Growth Rate 1975-85 | 4.9% | | 4.9% | | | 4.7% | | | 4.8% | |

[1]From Table 1-23.

[2]Only system peaks which occurred in morning are shown (January 1972 and 1974). System peak for year occurs in December or following January Forecast peaks are from summation of class peaks, Table I-29.

[3]Derived by (1) divided by [8760 x (3)]

[4]Only system peaks which occurred in evening are shown (December in 1970, others in January).

[5]Derived by (1) divided by [8760 x (6)]

[6]Summer peaks for 1976-1985 are assumed to be 99 percent of the preceding winter PM peak.

[7]Actual

to NEPLAN, NEES pointed out that its data was not the most probable forecast, but rather a reasonable range of forecasts within which to plan.

The NEES projections are based on the growth in winter peak load and annual energy requirements. The projections are listed in Table 3.9.

The "low growth" peak load projection, ranging from 0 to 4 percent per annum, represents the best estimate of electrical growth coincident with a 2 percent annual growth rate of total energy consumption in New England. This 2 percent growth rate is believed to be the minimum rate to sustain the economy. The "high growth" peak load projection, ranging from 4 to 10 percent per annum, is based on optimistic predictions of the New England economy and a concerted shift towards electric energy.

The corresponding energy medium growth forecasts range from a negative 0.1 percent to 7.5 percent per annum.

The median growth rates are suggested as a reasonable estimate for planning purposes. These amount to about 5.9 percent compounded annual growth over the next decade for peak load, and 6.0 percent for energy.

(c) Boston Edison

The Boston Edison Company operates without affiliates and controls about 16 percent of New England's generating capability. It services the Boston area of Massachusetts.

Boston Edison forecasts by the same sectors as Northeast Utilities -- residential, commercial, industrial, street lighting, railway, and wholesale. It prepares detailed energy forecasts for each sector for the next five years. In addition, it prepares peak load forecasts for the next ten years. Its energy and peak load forecasts are indicated in Tables 3.10 and 3.11, respectively.

The annual peak load for Boston Edison occurs in the summer -- as opposed to most other utilities

TABLE 3.9

NEW ENGLAND ELECTRIC SYSTEM
LOAD PROJECTIONS

| | Winter Peak | | | | | | Annual Energy | |
|---|---|---|---|---|---|---|---|---|
| | Low Growth | | High Growth | | Medium Growth | | Medium Growth | |
| | (Mw) | (%) | (Mw) | (%) | (Mw) | (%) | (Gwh) | (%) |
| 1974/75 | 2741 | - | 2741 | - | 2741 | - | 15126 | - |
| 1975/76 | 2741 | 0 | 2851 | 4 | 2796 | 2.0 | 15214 | - |
| 1976/77 | 2741 | 0 | 3022 | 6 | 2882 | 3.1 | 15145 | -0.1 |
| 1977/78 | 2796 | 2 | 3294 | 9 | 3045 | 5.7 | 16005 | 5.7 |
| 1978/79 | 2880 | 3 | 3590 | 9 | 3235 | 6.2 | 17003 | 6.2 |
| 1979/80 | 2995 | 4 | 3949 | 10 | 3472 | 7.4 | 18265 | 7.4 |
| 1980/81 | 3115 | 4 | 4344 | 10 | 3730 | 7.4 | 19605 | 7.3 |
| 1981/82 | 3240 | 4 | 4778 | 10 | 4009 | 7.5 | 21071 | 7.5 |
| 1982/83 | 3370 | 4 | 5160 | 8 | 4265 | 6.4 | 22417 | 6.4 |
| 1983/84 | 3504 | 4 | 5573 | 8 | 4539 | 6.4 | 23857 | 6.4 |
| 1984/85 | 3645 | 4 | 6019 | 8 | 4832 | 6.5 | 25397 | 6.5 |
| 1985/86 | 3790 | 4 | 6500 | 8 | 5145 | 6.5 | 27042 | 6.5 |
| 1986/87 | 3942 | 4 | 7020 | 8 | 5481 | 6.5 | 28808 | 6.5 |
| Compounded Annual Growth Rate: (Used in NEPLAN forecast) | | | | | | 5.94 | | 5.97 |

TABLE 3.10

BOSTON EDISON
FORECAST OF ENERGY SALES - Gwh

| Year | Residential | Commercial | Industrial | Street Lighting | Railway | Wholesale | Total | % Growth |
|---|---|---|---|---|---|---|---|---|
| 1976 | 2,632 | 4,205 | 1,738 | 108 | 24 | 783 | 9,490 | - |
| 1977 | 2,789 | 4,495 | 1,814 | 111 | 24 | 815 | 10,048 | 5.9 |
| 1978 | 2,952 | 4,810 | 1,894 | 114 | 24 | 848 | 10,642 | 5.9 |
| 1979 | 3,116 | 5,146 | 1,979 | 117 | 24 | 882 | 11,262 | 5.8 |
| 1980 | 3,287 | 5,502 | 2,064 | 121 | 24 | 917 | 11,915 | 5.8 |

TABLE 3.11

BOSTON EDISON
PEAK LOAD FORECAST

| | Winter | | Summer | |
|---|---|---|---|---|
| | (Mw) | (%) | (Mw) | (%) |
| 1975-76 | 1790 | - | 2045 | - |
| 1976-77 | 1900 | 6.1 | 2170 | 6.1 |
| 1977-78 | 2005 | 5.5 | 2300 | 6.0 |
| 1978-79 | 2115 | 5.5 | 2440 | 6.1 |
| 1979-80 | 2205 | 4.3 | 2590 | 6.1 |
| 1980-81 | 2320 | 5.2 | 2745 | 6.0 |
| 1981-82 | 2445 | 5.4 | 2915 | 6.2 |
| 1982-83 | 2570 | 5.1 | 3090 | 6.0 |
| 1983-84 | 2705 | 5.3 | 3280 | 6.2 |
| 1984-85 | 2850 | 5.4 | 3475 | 5.9 |
| 1985-86 | 3000 | 5.3 | 3685 | 6.0 |
| Compounded Annual Growth Rate: | | 5.3% | | 6.1% |

in New England. The higher forecasted growth rate for the summer load (6.1 percent versus 5.3 percent for the winter) contributes to the gradual shrinking of the difference between summer and winter loads for the region. Growth in energy demand is forecast as averaging about 5.9 percent.

- Residential sector energy demands represent a forecast 26.5 percent of the system in 1976, rising to 27.6 percent in 1980. This is significantly lower than the 37.4 percent for the whole of Massachusetts, no doubt due to greater commercialization in the Boston area. The forecast average growth in demand is 5.7 percent for the period.

- Commercial energy demand ranging from 44 percent of the system in 1976 to 46 percent in 1980, is significantly higher than the rest of Massachusetts. A growth rate of approximately 7.0 percent is forecast for this sector, which is indicative of a large city.

- Industrial sector demand is predicted to fall from 18 percent of the system in 1976 to 17 percent by 1980. Growth in total industrial energy consumption is forecast as an average 4.4 percent for this period.

- Street lighting energy demand is forecast at 2.9 percent growth.

- Railway demand is predicted at zero growth.

- Wholesale requirements are forecast to grow at 4.0 percent through 1980.

(d) Public Service Company of New Hampshire

This company supplies most of the power in the State of New Hampshire and a small part of Maine. More than 23 percent of energy sales in 1974 were to Government authorities and other utilities.

Detailed econometric studies have been made in the past for forecasting of residential, commercial, industrial, and other sectors of energy demand, and estimation of peak load on the basis of load factor predictions. Results of the latest detailed analysis, published in the fall of 1974, are shown in Tables 3.12 and 3.13.

- Residential demand in 1974 comprised 44 percent of the total supply area consumption (the average for the state is 43.5 percent). The forecast growth rate in 1974 was 8.6 percent through 1984, based on a population growth of about 1.6 percent and customer use growth of 2.2 to 3.0 percent.

- General (commercial) demand, which includes offices, small stores, services and small manufacturers is forecast on the basis of numbers of customers and average use projections. This sector comprised about 13 percent of the supply area in 1974 compared with 16.7 percent for the State as a whole. The projected growth in this sector in 1974 was 6.6 percent.

- Industrial sector energy demand includes industries, hotels, large offices, and stores, private schools and ski areas, and comprised about 42 percent of supply area demand in 1974 compared with 38.4 percent for the State. Projected growth in 1974 was 7.6 percent.

- Street lighting demand in 1974 was less than 1 percent of the State total and was forecast to grow through 1984 at an average 3.5 percent.

- Other demand was forecast in 1974 to increase at an average annual rate of 6.2 percent.

Total energy and peak load growth for the company was forecast in 1974 at 7.47 percent through 1984. Data published in the January 1, 1976, NEPOOL peak load forecast shows a reduction for PSCNH to 7.32 percent. Although the basis for this revision is not known, the forecasting procedure is the same.

(e) Central Maine Power Company[9]

The Central Maine Power Company services the central and southern areas of the State of Maine. Forecasts of energy consumption are based on

TABLE 3.12

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
ELECTRIC ENERGY SALES FORECAST 1974-1984 (GWh)

| Year | Residential | | General (Commercial) | | Industrial | | Street Lighting | | Other* | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | GWh | % | GWh | % | GWh | % | GWh | % | GWh | % | GWh | % |
| 1974 | 1553 | | 447 | | 1470 | | 25.6 | | 1056 | | 4552 | |
| 1975 | 1748 | 12.6 | 461 | 3.2 | 1591 | 8.2 | 26.5 | 3.5 | 1096 | 3.8 | 4925 | 8.2 |
| 1976 | 1912 | 9.4 | 487 | 5.7 | 1706 | 7.2 | 27.4 | 3.5 | 1159 | 5.7 | 5291 | 7.5 |
| 1977 | 2086 | 9.1 | 529 | 8.6 | 1843 | 8.0 | 28.4 | 3.6 | 1226 | 5.8 | 5712 | 8.0 |
| 1978 | 2272 | 8.9 | 576 | 8.9 | 2009 | 9.0 | 29.4 | 3.5 | 1302 | 6.2 | 6188 | 8.3 |
| 1979 | 2467 | 8.6 | 631 | 9.4 | 2175 | 8.3 | 30.4 | 3.4 | 1386 | 6.5 | 6689 | 8.1 |
| 1980 | 2674 | 8.4 | 676 | 7.1 | 2326 | 6.9 | 31.5 | 3.6 | 1476 | 6.5 | 7183 | 7.4 |
| 1981 | 2885 | 7.9 | 717 | 6.2 | 2491 | 7.1 | 32.6 | 3.5 | 1575 | 6.7 | 7703 | 7.2 |
| 1982 | 3102 | 7.5 | 759 | 5.8 | 2667 | 7.1 | 33.2 | 3.4 | 1682 | 6.8 | 8243 | 7.0 |
| 1983 | 3323 | 7.1 | 801 | 5.6 | 2853 | 7.0 | 34.9 | 3.6 | 1797 | 6.8 | 8809 | 6.9 |
| 1984 | 3549 | 6.8 | 844 | 5.4 | 3063 | 7.4 | 36.1 | 3.4 | 1923 | 7.0 | 9415 | 6.9 |
| Avg. Annual Growth (%) | | 8.6 | | 6.6 | | 7.6 | | 3.5 | | 6.2 | | 7.5 |

*Includes Government Authorities and firm sales to other utilities.

Source: Docket Nos. 50-443, 50-444. Application of PSCNH to the NRC, Atomic Safety and Licensing Board, regarding Seabrook Station Units 1 and 2.

TABLE 3.13

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
RESULTS OF FALL 1974 PEAK PROJECTIONS

| | | | January | | December | |
|---|---|---|---|---|---|---|
| Year | Prime Sales | Net Prime Output | Sales MWh | Peak MW | Sales MWh | Peak MW |
| 1975 | 4,922,700 | 5,290,400 | 474,400 | 1,022 | 451,500 | 1,065 |
| 1976 | 5,290,600 | 5,685,800 | 508,400 | 1,098 | 484,700 | 1,144 |
| 1977 | 5,712,200 | 6,138,900 | 548,400 | 1,186 | 536,900 | 1,235 |
| 1978 | 6,187,600 | 6,649,800 | 594,000 | 1,285 | 581,600 | 1,338 |
| 1979 | 6,688,800 | 7,188,400 | 642,100 | 1,389 | 628,700 | 1,447 |
| 1980 | 7,183,300 | 7,719,800 | 689,600 | 1,491 | 675,200 | 1,554 |
| 1981 | 7,700,700 | 8,275,900 | 739,300 | 1,599 | 723,900 | 1,666 |
| 1982 | 8,243,200 | 8,858,900 | 791,300 | 1,711 | 774,900 | 1,783 |
| 1983 | 8,809,400 | 9,467,400 | 845,700 | 1,829 | 828,100 | 1,905 |
| 1984 | 9,415,300 | 10,118,500 | 903,900 | 1,955 | 885,000 | 2,036 |
| Avg. Annual Growth: | 7.47% | 7.47% | | 7.47% | | 7.46% |

NEPOOL Forecast January 1, 1976

| Year | Winter Peak(MW) |
|---|---|
| 1975/76 | 1030 (Jan.) |
| 1976/77 | 1109 (Jan.) |
| 1977/78 | 1138 (Dec.) |
| 1978/79 | 1287 |
| 1979/80 | 1386 |
| 1980/81 | 1493 |
| 1981/82 | 1598 |
| 1982/83 | 1709 |
| 1983/84 | 1829 |
| 1984/85 | 1957 |
| 1985/86 | 2094 |
| 1986/87 | 2241 |
| Avg. Growth | 7.32% |

sectoral projections from historical trends. A computer model is used, but this does not have a true econometric basis. Growth rates are selected by judgment on the basis of known economic trends. The available projections are shown in Table 3.14.

- Residential sector energy demand is predicted to grow at about 6.2 percent through 1985, and in 1974 was 39.6 percent of the company load excluding sales to other utilities. In the state of Maine as a whole, residential demand accounted for 38.6 percent of consumption in 1974.

- Commercial energy consumption was 21.2 percent of the company total excluding sales to other utilities in 1974, compared with 20.6 percent for the total state. Growth in this sector is predicted as about 9 percent through 1985.

- Industrial energy demand comprised 37.7 percent of the CMP Co. load exclusive of external sales in 1974, very similar to the 37.2 percent proportion reported for the whole State. Growth in this sector is predicted to be about 4 percent.

- Street lighting and other public sectors of demand accounted for 1.7 percent of the total exclusive of external sales in 1974, compared with 1.0 percent for the entire State. Growth in this sector is also predicted at 4 percent.

Total energy sales projections are forecast at a 6.3 percent growth rate through 1985 and peak (winter) load demand at 6.0 percent through 1986.

(f) United Illuminating Company

The United Illuminating Company is an investor-owned utility operating without affiliates. It services a number of towns in Connecticut and accounts for about 6 percent of New England's generating capability[7].

The highest recorded system peak of 859 MW occurred in the summer of 1973. After some years of uncertainty, this peak is predicted

TABLE 3.14

CENTRAL MAINE POWER COMPANY
ENERGY SALES AND PEAK LOAD FORECASTS
1974 - 1986

| Year | Energy Sales: Residential MWh | % | Commercial MWh | % | Industrial MWh | % | Public MWh | % | Other MWh | % | Total MWh | Peak Load (DEC.) MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1974** | 1,820 | 34.5 | 969 | 18.4 | 1,732 | 32.8 | 79 | 1.5 | 676 | 12.8 | 5276 | 905 |
| 1975 | 1,826* | | 974* | | 1,736* | | 80* | | 678* | | 5294* | 1033*** |
| 1976 | | | | | | | | | | | 5566 | 1025 |
| 1977 | | | | | | | | | | | 6024 | 1090 |
| 1978 | | | | | | | | | | | 6343 | 1160 |
| 1979 | | | | | | | | | | | 6729 | 1241 |
| 1980 | | | | | | | | | | | 7157 | 1327 |
| 1981 | | | | | | | | | | | 7613 | 1420 |
| 1982 | | | | | | | | | | | 8100 | 1520 |
| 1983 | | | | | | | | | | | 8623 | 1628 |
| 1984 | | | | | | | | | | | 9181 | 1741 |
| 1985 | 3,332* | | 2,306* | | 2,570* | | 118* | | 1,449* | | 9775* | 1852 |
| 1986 | | | | | | | | | | | -- | 1969 |
| Assumed Growth Rate | 6.2* | | 9.0* | | 4.0* | | 4.0* | | 7.9* | | 6.3 | 6.0 |

* Note: Assumed or estimated figures based on data provided by CMPC, March 1976.

** Source: Central Maine Power Company Financial and Statistical Review, 1964-1974.

*** Source: New England Load and Capacity Report, 1975-1986, NEPLAN January 1, 1976.

to be exceeded in 1976. Because of these uncertainties in load growth, UI have followed a "bandwidth" procedure for the 1976 forecast (Table 3.15). The forecast was made for peak load only, which for the United Illuminating system occurs in the summer, between June and September.

The system low growth rate is forecasted as 4 percent annually, and this rate was adopted by NEPOOL for the New England 10-year forecast of January 1976. The high growth rate assumes that electrical demand could return to levels consistent with historic growth rates (i.e. 7 percent).

About 28 percent of UI energy sales are to manufacturing customers, concentrated mostly in durable goods. These industries have only recently given indications of having begun an economic recovery. On this basis, customer energy requirements are predicted as 4-1/2 percent greater in 1976 over 1975.

In the future, UI plans to participate with NEPOOL in the development of an econometric load forecasting model.

(g) Central Vermont Public Service Company

This company supplies a large area of the State of Vermont.

The energy forecasting methods used by CVPSC are the traditional techniques of historical trending, taking account of known or forecast social and economic influences, in the residential, commercial, industrial, and public sectors. However, it is recognized that such approaches could be unreliable in the current period of uncertainty and efforts are being made to explore more sophisticated econometric methods of forecasting.

Generally, peak loads are forecast on the basis of trends in load factor, with due allowance being taken in the future for a vigorous load management effort aimed at improving load factor.

TABLE 3.15

UNITED ILLUMINATING
PEAK (SUMMER) LOAD FORECAST - Mw

| Year | Low Growth (Mw) | Low Growth (%) | High Growth (Mw) | High Growth (%) |
|---|---|---|---|---|
| 1976 | 898 | - | 963 | - |
| 1977 | 934 | 4 | 1,045 | 8.5 |
| 1978 | 971 | 4 | 1,118 | 7.0 |
| 1979 | 1,010 | 4 | 1,195 | 6.9 |
| 1980 | 1,050 | 4 | 1,278 | 6.9 |
| 1981 | 1,092 | 4 | 1,367 | 6.9 |
| 1982 | 1,136 | 4 | 1,462 | 6.9 |
| 1983 | 1,181 | 4 | 1,564 | 7.0 |
| 1984 | 1,228 | 4 | 1,672 | 6.9 |
| 1985 | 1,278 | 4 | 1,789 | 7.0 |
| 1986 | 1,329 | 4 | 1,913 | 6.9 |
| 1987 | 1,382 | 4 | 2,043 | 6.8 |
| 1988 | 1,437 | 4 | 2,180 | 6.7 |
| 1989 | 1,495 | 4 | 2,324 | 6.6 |
| 1900 | 1,555 | 4 | 2,475 | 6.5 |
| 1991 | 1,617 | 4 | 2,636 | 6.5 |
| 1992 | 1,681 | 4 | 2,807 | 6.5 |
| 1993 | 1,749 | 4 | 2,990 | 6.5 |
| 1994 | 1,819 | 4 | 3,184 | 6.5 |
| 1995 | 1,891 | 4 | 3,391 | 6.5 |
| Compounded Annual Growth Rate: | | 4% | | 6.8% |
| Growth Rate Assumed in NEPLAN Forecast: | | 4% | | (7.1% through 1985) |

Peak load and energy forecasts by sector through 1985 are shown in Table 3.16.

- Residential sector energy demand is predicted to grow at an average 5.5 percent through 1985. This sector represents 45.2 percent of the Service Company area demand, slightly less than the State average of 48.0 percent in 1974.

- Commercial demand is about 10.1 percent of the company area total and is forecast to grow at 5.0 percent per annum through 1985. The State commercial demand was 17.9 percent in 1974.

- Industrial sector energy demand is 38.3 percent of the company area whereas the State industrial sector accounted for 28.6 percent of demand in 1974. Annual growth is forecast at 3.5 percent.

Total energy growth for the CVPSC system is predicted as 4.5 percent through 1985, in contrast with winter peak load growth which is forecast as 3.7 percent per annum.

## 3.04 - Future Load Growth

The previous section presented various forecasts of load growth in New England. A summary of the major contributors to the total NEPOOL forecast is presented in Table 3.1.

The utilities have realized the inaccuracy inherent in their traditional forecasting methods. The recent economic slump and energy crisis have left the electric utility industry with increasing uncertainties. The recovery of electric load growth is tied directly with the recovery of the economy and the changing consumption patterns of the public. Such factors are difficult, if not impossible, to predict.

Increasingly, therefore, utilities are altering their forecasting procedures. Instead of developing specific forecasts, some are predicting a "bandwidth" of forecasts, based on low and high growth rates. Also, the utilities are reluctant to forecast much further than ten years.

TABLE 3.16

CENTRAL VERMONT POWER SERVICE CORPORATION
TEN-YEAR ENERGY AND PEAK LOAD FORECAST

| Year | MWh Residen-tial | MWh Commer-cial | MWh Indus-trial | MWh Light-ing | MWh Government Authorities | MWh Sub-total | MWh Sales for Resale | MWh Co. Use | MWh System Losses | MWh Total | MW Winter Peak |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1976 | 680,555 | 152,263 | 576,071 | 7,883 | 88,518 | 1,505,290 | 41,000 | 3,600 | 139,490 | 1,689,380 | 356 |
| 1977 | 701,238 | 159,937 | 591,067 | 7,883 | 90,323 | 1,550,448 | 42,000 | 3,700 | 143,653 | 1,739,801 | 360 |
| 1978 | 728,687 | 167,792 | 608,297 | 7,883 | 90,055 | 1,604,714 | 43,500 | 3,800 | 148,681 | 1,800,695 | 372 |
| 1979 | 765,032 | 176,164 | 625,941 | 7,883 | 93,883 | 1,668,903 | 45,000 | 3,900 | 154,602 | 1,872,405 | 384 |
| 1980 | 803,053 | 184,919 | 647,408 | 7,883 | 95,734 | 1,738,997 | 47,000 | 4,000 | 161,100 | 1,951,097 | 396 |
| 1981 | 851,124 | 194,140 | 669,949 | 7,883 | 97,634 | 1,820,730 | 49,000 | 4,100 | 168,645 | 2,042,475 | 412 |
| 1982 | 903,383 | 203,890 | 696,658 | 7,883 | 98,632 | 1,909,446 | 51,500 | 4,200 | 176,863 | 2,142,009 | 403 |
| 1983 | 965,213 | 214,010 | 723,957 | 7,883 | 99,583 | 2,010,646 | 54,000 | 4,300 | 186,205 | 2,255,151 | 450 |
| 1984 | 1,033,163 | 224,794 | 752,763 | 7,883 | 100,618 | 2,119,221 | 57,000 | 4,400 | 196,256 | 2,376,877 | 472 |
| 1985 | 1,105,659 | 236,071 | 782,407 | 7,883 | 101,639 | 2,233,659 | 60,500 | 4,500 | 206,879 | 2,505,538 | 493 |
| Avg. Growth | 5.54% | 4.99% | 3.46% | | | 4.48% | | | | | 3.68% |

The utilities recognize the inherent weaknesses in their forecasting procedures and are supporting, through NEPOOL, the development of an econometric forecasting model for the region. However, the model is not yet available and will have to be proven.

Thus, the NEPOOL forecast represents the only total New England projection available at this time. As mentioned previously, it is based on individual utility forecasts. These forecasts, in turn, appear to be based on a gradual economic recovery over the next few years.

### 3.04.1 - Load Forecasts

#### (a) Peak Load

Table 3.1 presents a summary of the forecasted growth rates of a number of New England utilities. There is considerable variation in the peak load growth rates -- from 3.7 percent annually for CVPSC to 7.3 percent for PSCNH.

The reasons for these variations are not clear. For example, the NEES estimate of 6.3 percent (which is the median of a high-low bandwidth forecasting approach) is significantly higher than the 4.5 percent growth forecast by NUS. Yet, the structure of these two utilities and the essential geographic, economic and population characteristics of their supply areas are quite similar.

Also, the growth rates forecast by PSCNH and CMP are also high in relation to other New England utilities. In the case of PSCNH, the main influences would appear to be high growth rates forecasted in the residential (8.4 percent) and industrial (7.4 percent) sectors. In the case of CMP, the influence is from the forecasted growth in the commercial sector (9.0 percent).

It is appropriate to assess the sensitivity of the total New England forecast to reductions in the individual forecasts for the following four cases:

(i) Reduce NEES total growth from 6.3 percent to 5 percent (which represents the difference between the 4.5 percent average growth rate

TABLE 3.17

PEAK LOAD FORECAST SENSITIVITY ANALYSIS

| | Utility | Parameter Considered | Current Value * (%) | Adjusted Value (%) | Current Annual Growth of Utility * (%) | Adjusted Average Annual Growth: Utility (%) | Adjusted Average Annual Growth: Total New England (%) |
|---|---|---|---|---|---|---|---|
| (i) | NEES | Average Annual Growth | 6.3 | 5.0 | 6.3 | 5.0 | 5.2 |
| (ii) | PSCNH | Residential Growth | 8.4 | 6.0 | 7.3 | 6.3 | 5.4 |
| (iii) | PSCNH | Industrial Growth | 7.4 | 5.0 | 7.3 | 6.4 | 5.4 |
| (iv) | CMP | Commercial Growth | 9.0 | 7.0 | 6.0 | 5.5 | 5.4 |
| (v) | PSCNH | (Residential<br>(Industrial | 8.4<br>7.4 | 6.0)<br>5.0) | 7.3 | 5.3 | 5.3 |
| (vi) | (NEES<br>(CMP | Average Annual Growth<br>Commercial | 6.3<br>9.0 | 5.0<br>7.0 | 6.3<br>6.0 | 5.0)<br>5.5) | 5.2 |
| (vii) | Combined (v) and (vi) - - - - - - - - - - - - - - - - - - - - - - - | | | | | | 5.0 |

* See Table 3.1

of the utilities in Table 3.1 -- excluding NEES, PSCNH, CMP -- and the NEPOOL forecast of 5.5 percent).

(ii) Reduce PSCNH residential growth rate from 8.4 percent to 6 percent (5.9 percent is the average forecasted residential growth rate of the five utilities in Table 3.1).

(iii) Reduce PSCNH industrial growth rate from 7.4 percent to 5 percent (4.8 percent is the average forecasted industrial growth rate of the five utilities in Table 3.1).

(iv) Reduce CMP commercial growth rate from 9.0 percent to 7 percent (6.8 percent is the average forecasted commercial growth rate of the five utilities in Table 3.1).

Additionally, the impact of combinations of these four cases should also be assessed. These include:

(v) Combine (i) and (iii).

(vi) Combine (i) and (iv).

(vii) Combine (v) and (vi).

The results of the analysis are presented in Table 3.17. The adjustment of the NEES forecast alone reduces the total New England forecast to 5.2 percent. Changes in the PSCNH or CMP forecasts produce a total New England growth rate of about 5.4 or 5.3 percent. The maximum reduction of NEPOOL's forecast could be to 5.0 percent.

(b) Energy

The recent trend has been that the growth in energy consumption has not declined as much as the growth in peak load. That is, on an annual basis, the system load factor is increasing. This is primarily due to the decreasing gap between winter and summer peak loads.

The sectoral forecasting procedures used by many utilities are designed primarily to yield an estimate of energy consumption. This is because it is energy consumption that can be related to units

TABLE 3.18

RECOMMENDED NEW ENGLAND PEAK LOAD AND ENERGY FORECAST 1975 - 2000

| Year | Winter Peak Load (MW) | Year | Annual Energy (GWh) | Load Factor* Percent |
|---|---|---|---|---|
| 1975/76 | 13,908 | 1976 | 77,096 | 60.10 |
| 1980/81 | 17,920 | 1980 | 95,508 | 60.78 |
| 1985/86 | 23,090 | 1985 | 124,826 | 61.83 |
| 1990/91 | 29,751 | 1990 | 163,142 | 62.71 |
| 1995/96 | 38,334 | 1995 | 213,220 | 63.61 |
| 2000/01 | 49,392 | 2000 | 278,671 | 64.52 |
| Average Annual Growth Rate: | 5.2% | | 5.5% | |

*Based on December peak load in that year.

of goods and services. It is only the coincidence of energy consumption that yields the peak load. Hence, the forecast of energy consumption is more stable in comparison to the forecast of peak load.

The NEPOOL forecast of energy consumption is currently based on an estimated 5.5 percent annual growth.

(c) Analysis of Peak and Energy Forecasts

Estimates of energy consumption are based upon a number of economic, geographic, and social factors. Estimates of peak load are derived from the energy forecasts by allowing for the coincidence of the various load elements. However, significant portions of the electrical load are dependent upon the weather -- for both air conditioning in summer and space heating in winter. Extremes in the weather result in major changes in peak load with relatively minor changes in energy consumption. Thus, trends in peak load show greater variability than those for energy. Since the planning of generating and transmission capability must be based on meeting the peak power requirements, the peak load forecasts proposed by utilities generally include sufficient allowance for weather extremes.

This is satisfactory when no one year is given more weight in an economic analysis than any other. However, in the current analysis, three specific years (1985, 1990 and 2000) have been selected for detailed study. For this analysis, the predicted peak load should be based on average weather conditions rather than allow for some extreme. For this reason alone, the forecast of peak load should be lower than that used by the utilities.

However, a more specific reason to reduce the peak load forecast is the historic trend in increasing annual load factor. Even when the New England utilities relied for the most part on conventional thermal generation, there was a clear trend to higher annual load factors (see Figure 3.5). With the increasing shift to nuclear power, there is greater incentive to improve the load factor since nuclear power has relatively low marginal costs. Thus, there is a positive incentive for individual utilities to actively promote and encourage changes in consumer patterns even without the specific load management measures currently contemplated.

It is therefore appropriate to anticipate a slow but steady improvement of annual load factor rather than the NEPOOL estimate of a constant load factor of 60.8 percent. A load factor of 61.8 percent in 1985 associated with a growth in energy consumption of 5.5 percent per annum would correspond to a growth in peak load of 5.2 percent. This value has consequently been selected.

The selection of this value is also consistent with the results of the sensitivity analysis in Section 3.04.1(a). The resulting peak load and energy forecasts to the year 2000 are indicated in Table 3.18.

GENERAL REFERENCES


1. "Electric Power Demand and Supply in New England; A Review of Trends and Forecasts", New England Regional Commission, January 1975 (prepared by Booz-Allen and Hamilton, Inc.).

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5. "Data on Coordinated Regional Bulk Power Supply Programs", Northeast Power Coordinating Council, April 1, 1975.

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8. Docket Nos. 50-443, 50-444, Application of PSCNH to the NRC, Atomic Safety and Licensing Board, regarding Seabrook Station Units 1 and 2.

9. Central Maine Power Company, Financial and Statistical Review, 1964-1974.

# 4 - ALTERNATIVE MEANS OF MEETING DEMAND

As discussed in Chapter 3, prudent planning calls for the assumption that electric power and energy demand in New England will increase for the next ten years at average rates of approximately 5.2 percent and 5.5 percent per annum respectively. The implementation of load management techniques and control devices, and the effects of conservation could significantly reduce the growth in peak load and in energy demand. The primary goal in the planning and operation of an electric power system is to provide, at minimum overall cost, the capability to meet with an adequate margin of reserve the projected demand at all times. The achievement of this goal requires that a number of complex requirements related both to the characteristics and magnitude of the load to be met, and to the characteristics of the generating facilities designed to meet this load, be met.

The prime requisite is the establishment of an orderly and economic long-term expansion program related to the identified demand. The power system must also retain an adequate margin of generating capacity to meet planned and unplanned plant outages, with sufficient flexibility to allow for rapid fluctuations in demand.

Expansion of an electric power system may in theory be achieved by means of the combinations of a large number of available types and sizes of power generation or energy storage facilities. However, the selection of the optimum mix and scheduled installation of facilities to meet the above objectives is usually limited to a relatively small number of choices. In this chapter, all available, or potentially available, power generation and energy storage concepts are briefly reviewed in order to select for further evaluation those which appear to be viable in the New England system in the next 10 to 20 years.

A summary of Chapter 4 follows in Section 4.01. The requirements for system capability and the current (January 1, 1976) planned NEPOOL expansion program are discussed in Section 4.02. A list of some 24 basic alternatives for power generation and energy storage is reviewed in Section 4.03. Some of these alternatives are already operational, others are in various stages of development. Ten types of installation are selected for further evaluation by application of a preliminary screening process in Section 4.04. In Section 4.05, the capital and operating costs of the selected alternatives are reviewed and developed. The resulting output is considered in the assessment of the economic, environmental, and social impacts of the alternatives on the New England System in Chapters 5 and 6.

## 4.01 - Summary

The objective of power system planning is to ensure that forecast load demands can be met with a high degree of assurance and at minimum net cost to the system. This in turn requires not only the provision of an adequate reserve of generating capacity to meet planned and unplanned system outages, but also the provision of an appropriate mix of base-load, intermediate, and peaking generating capacity to most economically follow the daily, weekly, and monthly variations in system demand.

Reserve margin is traditionally at least 20 percent of coincident peak load. However, due to the recent dramatic decline in demand, the margin in New England has become considerably greater. The December 1975 total capability of the New England System was 20,212 MW of generating capacity. The recorded peak load in December 1975 was 13,529 MW. Total capability increased to 20,571 MW in January 1976, when the recorded peak load was 13,908 MW, indicating an actual reserve margin of 47.9 percent.

Selection of the appropriate "mix" of future generating capability requires consideration not only of technical feasibility and economy, but also of potential fuel availability and the socio-economic and environmental impact of the alternatives available. Other parameters include the lead time required to license and construct a facility, and the availability of renewable and non-renewable resources for its construction and operation.

Twenty-four potential alternative modes of energy generation and storage initially reviewed as alternatives to the Dickey-Lincoln project are summarized in Table 4.1, categorized in accordance with their current state of engineering development. A process of preliminary

TABLE 4.1

INITIAL COMPILATION OF ALTERNATIVES

| State of Development | Direct Generation Alternatives: Type | Operating Mode* | Energy Storage (Peaking) Alternatives |
|---|---|---|---|
| In General Use | Conventional Thermal Steam Cycle | B/M | Conventional Pumped Hydro |
| | Diesel Power | P | |
| | Gas Turbines | P | |
| | Hydroelectric | B/M/P | |
| | Nuclear Steam Cycle (LWR,HWR) | B | |
| | (Power Purchase | B/M/P) | |
| Developed But in Limited Use | Combined Cycle Thermal | M | Batteries (lead acid) |
| | Geothermal | B | |
| | Nuclear Steam Cycle (LMFBR, GCFR, LWBR) | B | |
| | Tidal Hydroelectric | M | |
| Experimental | Alternative Fuels | B/M/P | Batteries (Advanced) |
| | Fuel Cells | P | Flywheels |
| | Magneto-Hydrodynamic/ Steam Cycle | M | Super Conducting Magnetic Storage |
| | Nuclear Steam Cycle (HTGR, Fusion) | B | Thermal Storage (Steam or Chemical) |
| | Solar (Photovoltaic or Thermal) | M/P | Underground Compressed Air Storage |
| | Wind | M/P | Underground Pumped Hydro |

*Abbreviations: B: Base-load plant
M: Mid-range plant
P: Peaking plant

screening has been applied to this list to select for further evaluation those which are considered technically feasible in adequate unit capacity sizes in the 1985-1990 time frame.

In the preliminary screening of alternatives for consideration in subsequent detailed studies, all those concepts currently in general use with the exception of diesel power have been accepted. Diesel power was rejected because of high costs and limited scale of application. Of the concepts "Development in limited use" only the combined cycle concept, a mid-range application of the gas turbine, has been accepted. Geothermal was rejected because of unproven resources and economics in the New England area; advanced nuclear cycles such as the LMFBR and LWBR have been excluded since they are not likely to replace the LWR in the U. S. nuclear scene before 1990. Tidal hydroelectric power, which is currently under study at the Passamaquoddy site, was rejected on the basis of, as yet, unproven economic viability.

Of those concepts categorized as "Experimental", only underground compressed air storage and underground pumped hydroelectric storage were accepted. The balance, which included alternative fuels, MHD, nuclear (HTGR, Fusion), advanced batteries, flywheels, superconducting magnetic storage, and thermal storage, have been rejected generally on the basis of inadequate demonstration that commercial feasibility can be achieved within the 1985-1990 time frame. Fuel cells have also been rejected because their commercial viability in New England has yet to be demonstrated. Although it is recognized that both solar and wind power application are the subject of intense development work at the present time, it is considered more appropriate to consider the potential impact of these concepts within the context of load demand modification, rather than as sources of power generation.

The ten alternatives selected for more detailed evaluation and selection on the basis of cost, therefore, are:

(a) Direct Generation

Conventional fossil thermal steam cycle;
Gas turbines;
Hydroelectric;
Nuclear steam cycle;
Combined cycle;
Lead acid batteries;
Power purchases.

(b) Energy Storage

Conventional pumped hydro;
Compressed air storage;
Underground pumped hydro.

## 4.02 - Planned System Capability

The main objective of a system planning procedure is to insure the provision and operation of an economic, reliable, and flexible combination of electricity supply facilities to meet the power and energy demands of the system at all times.

System capacity planning decisions are currently based on a forecast of demand 8 to 10 years in the future. Having regard to the long lead times required to construct and commission many types of large power generating facilities, the consequences of either poor forecasting or sudden shifts in consumption patterns are obvious. If too little capacity is installed, there is a risk of shortages, "blackouts", etc. To overcome such occurrences, expensive, short-term decisions may have to be made, such as purchasing expensive power from another utility, or selecting alternatives with short lead times even though they have high operating costs. Conversely, if too much capacity is installed, the utility must pay for facilities that are not earning revenue or attempt to sell power, often at disadvantageous rates to adjacent utility systems. Thus, the overall cost of energy increases.

The planned system capability must, therefore, comprise a "trade-off" all of these considerations -- system mix, reserve margin, and accuracy of forecast against a judgment of the economic impact of the plan on the region and the insurance against power shortages.

The development of, and constraints on, the current NEPOOL system capability plan for the period to 1980/87 is discussed in Section 4.02.

### 4.02.1 - New England Capacity Planning

In New England capacity planning is currently carried out solely by the utilities. Coordination of the planning function and establishment of the size, type, and service area of each new plant is provided by NEPOOL. The individual utility has responsibility for both specific site and design decisions and financial arrangements.

The capacity and energy requirements of the New England System through the year 2000 are reviewed in Chapter 3. System capacity must be planned so that the demands will continue to be met when unexpected mechanical or electrical equipment failures develop in the facilities, or certain items of equipment are undergoing scheduled maintenance. The total capacity available on the system, or "capability", must therefore be greater than the forecast demand by what is termed the "reserve margin".

### 4.02.2 - Reserve Margins

The reserve margin depends upon the desired reliability standards of the system and is related to the anticipated extent of forced and planned outages. The reserve margin will also depend upon a number of other characteristics of the system, including:

- The combination of facilities which together make up the total generating capacity of the system, i.e. the system "mix", (some types are inherently more reliable than others);

- The size of units (a large unit, relative to the size of the system, demands more reserve since its loss would severely curtail total generation);

- Transmission interconnections to other systems (by providing access to other systems, the potential effect of system failure is usually reduced).

Typically, reserve margins are about 20 percent or more of the forecasted peak load. Recently, however, the reserve margin in New England has grown substantially to about 50 percent (see Table 4.1) due to a pronounced reduction in energy consumption. In other words, the

TABLE 4.2

NEW ENGLAND SYSTEM CAPABILITIES
WINTER - 1976/77 - 1986/87*, 1990 & 2000**

| | | | | Megawatts | | | |
|---|---|---|---|---|---|---|---|
| | Actual Dec.75 | 1976/77 | 1977/78 | 1978/79 | 1979/80 | 1980/81 | 1981/82 |
| Total Capability*** | 20212 | 22145 | 22199 | 22799 | 22802 | 22804 | 24225 |
| Total Peak Load | 13529 | 14518 | 15317 | 16159 | 17107 | 18129 | 19191 |
| Reserve Before Maintenance | 6683 | 7627 | 6882 | 6640 | 5695 | 4675 | 5034 |
| % Reserve Before Maintenance | 49.4 | 52.5 | 44.9 | 41.1 | 33.3 | 25.8 | 26.2 |
| Scheduled Maintenance | 3352 | 1040 | 762 | -- | -- | -- | -- |
| Reserve After Maintenance | 3331 | 6587 | 6120 | 6640 | 5695 | 4675 | 5034 |
| % Reserve After Maintenance | 24.6 | 45.4 | 40.0 | 41.1 | 33.3 | 25.8 | 26.2 |

* From New England Load and Capacity Report, 1975-1986, NEPLAN, Jan. 1976.

** Estimates based on load forecasts in Chapter 3 and 20% reserve margin.

*** Additions include only "NEPOOL Planned" generating capacity (includes 424.75 MW of deactivated reserve).

Table 4.2
New England System Capabilities - 2

| | Megawatts | | | | | | |
|---|---|---|---|---|---|---|---|
| | 1982/83 | 1983/84 | 1984/85 | 1985/86 | 1986/87* | 1990/91** | 2000/01** |
| Total Capability*** | 26676 | 27828 | 28979 | 28778 | 30878 | 37463 | 64601 |
| Total Peak Load | 20249 | 21369 | 22578 | 23831 | 25105 | 31219 | 53834 |
| Reserve Before Maintenance | 6427 | 6459 | 6401 | 4947 | 5773 | 6244 | 10767 |
| % Reserve Before Maintenance | 31.7 | 30.2 | 28.4 | 20.8 | 23.0 | 20.0 | 20.0 |

forecast load growth did not materialize. Current forecasts indicate that this margin will reduce to about 20 percent by 1985/86.

### 4.02.3 - Factors Affecting System Planning

The system generating capacity requirement is obviously closely related to forecast system demand. A number of other factors must also be taken into consideration in the design of a system expansion plan:

- Selected system mix;
- Required lead times for selected installations;
- Resource availability (capital, labor, fuels, and materials).

#### (a) Selection of System Mix

The continuous and rapid fluctuation in system load from hour to hour, day to day, and week to week demands a carefully selected combination of generating facilities capable of following these variations at least cost. A large proportion of the daily load is relatively constant. Nevertheless, this constant fraction or "base load" may vary appreciably from season to season. At certain times of the day, generally about 8:00 a.m. and 6:00 p.m., the system demand reaches its instantaneous maximum or "peak" values. Between the extremes of base load and peak is a region known as "mid-range" load.

A number of plants such as nuclear and conventional thermal plants perform most efficiently under constant load conditions and are described as "base-load" plants; every effort is therefore made to operate these plants at very high capacity factors. While on a daily basis this might be close to 100 percent, on an annual basis, it may not be more than 80 percent because of maintenance or mechanical shutdowns. The newest, most efficient units on a system are generally designated as base-load units because they are the least costly to run.

All other generating facilities in the system operate in a cycling mode, generating for only a portion of each day. In turn, these plants are further divided into two categories -- "peaking" and "mid-range". Peaking plants may operate for as little as one or two hours a day, and are typically designed for a long-term capacity factor of 10 percent or less. Mid-range generation fills the gap between peaking and base (from 10 to 80 percent capacity factor).

Peaking units must be capable of being brought on line quickly to meet system demands which last for short periods. Typically, thermal peaking units, such as gas turbines, are low in capital cost, not very efficient, and often are operated for less than 1,000 hours per year. Alternatively, peak generation may be provided by hydroelectric or pumped storage plants which, though high in capital cost, are inexpensive to operate.

Mid-range generation is often provided by the small, old, less efficient thermal units. These units are run for several hours a day when the load demand requires an increment of power above that provided by base-load units. Mid-range units are normally run from approximately 2,000 to 4,000 hours per year.

The selection of the mix of generating facilities to meet the total requirements of the system operation must also take into account:

- Technical feasibility of the particular type of facility selected;
- Fuel availability;
- Socio-economic and environmental impacts.

- <u>Technical Feasibility</u> - A power supply utility will usually base its planned capability on types of facility which have been successfully proven in commercial applications. Nevertheless, utilities do recognize the need for technical innovation and frequently invest substantial amounts on research into advanced technologies. This subject is discussed further in Section 4.03.3.

- Fuel Availability - A power plant converts energy from one form or another into electricity. If the source of energy is water, the wind or sun, it is presumed to be available at the power source and only its incidence or occurrence may be in doubt. If however, the energy source is coal, oil, gas, or nuclear fuel, the fuel must be obtained and transported to its point of use.

  New England has no large deposits or sources of fuel. Fossil and nuclear fuels must be transported by railroad, pipeline, ship, barge, or trucks. Fossil-fired units of the size being considered must receive fuel by rail, barge, pipeline, or ship because of the quantities of fuel involved. Nuclear fuel is generally transported by truck.

  The impact of these factors is discussed in more detail in Section 4.03.3.

- Socio-economic and Environmental Impacts - Power supply facilities affect the environment in a considerable number of different ways. The impact of different types of development may also vary from the relatively minor to the highly significant. All of these impacts must be taken into account by the utility in planning its future capability expansion program. The difficulty, cost, and time required to reconcile the environmental factors may influence the selection of alternatives to a significant extent.

  Environmental factors are discussed more fully in Section 4.03.3 and Chapter 6.

(b) Required Lead Times

The time between the decision to build a power supply facility and the first commercial production of power, the "lead time", is highly significant. Lead times may vary from two or three years for a small gas turbine or diesel plant to as much as 10 to 13 years for the major nuclear or pumped hydro types of plant. These prolonged periods are necessary for the planning and feasibility studies to be completed as well as the licensing, design construction, and equipment manufacture.

These factors will be examined in greater depth in Chapter 5.

(c) <u>Resource Availability</u>

The major resources required for construction and operation of a power supply facility are capital, materials, and labor.

The first cost considered is the amount of dollars required to finance the construction of the power facility. This cost, as well as operation costs, must be minimized in order to keep to a minimum the cost of power to the consumer.

Other costs are also associated with the consumption of non-renewable natural resources. In a similar way, the land occupied by the facility is removed from some of its present or potential uses. However, it may be possible to restore some of the land at some time in the future, after the project has been constructed.

Similarly, fuel supply and transportation costs will be most significant during the operation of the facility and must be taken into account.

These factors will be discussed at greater length in Section 4.03.3.

### 4.02.4 - New England System Capability

The New England System capability currently planned for the period 1976/77 through 1986/87 is shown in Table 4.1. NEPOOL's authorized capacity additions excluding plant retirements and re-ratings is shown in Table 4.3.

These data have been adopted as the basis for system expansion plans with and without the Dickey-Lincoln School Lakes Project, to be developed in Chapter 5.

TABLE 4.3

NEPOOL AUTHORIZED CAPACITY ADDITIONS

| Company | Station | Type | Fuel | Winter Capacity (MW) | Expected Date of Operation |
|---|---|---|---|---|---|
| NEGEA & EUA | Canal #2 | IF | Oil | 560 | February 1976 |
| Northeast Utilities | Millstone #2 | N | Nuclear | 830 | March 1976 |
| Taunton Municipal Light Plant | B.F. Cleary #9 | IF | Oil | 20 | April 1976 |
| Braintree Electric Light Dept. | Potter #2 | CC | Oil | 95 | November 1976 |
| Maine Electric Power Company | Purchase from New Brunswick | -- | -- | 200 | From June 1976 to 1985 |
| Maine Electric Power Company | Purchase from New Brunswick | -- | -- | 200 | From October 1976 to 1986 |
| Central Maine Power Company | W.F. Wyman #4 | IF | Oil | 600 | December 1978 |
| Public Service Co. of N.H. | Seabrook #1 | N | Nuclear | 1150 | June 1981 |
| Mass. Municipals | Stonybrook | CC | Oil | 270 | November 1981 |
| Northeast Utilities | Millstone #3 | N | Nuclear | 1150 | May 1982 |
| Boston Edison | Pilgrim #2 | N | Nuclear | 1180 | October 1982 |
| Mass. Municipals | Stonybrook | GT | Oil | 120 | November 1982 |
| Public Service Co. of N.H. | Seabrook #2 | N | Nuclear | 1150 | June 1983 |
| New England Electric System | NEPCO #1 | N | Nuclear | 1150 | November 1984 |
| New England Electric System | NEPCO #2 | N | Nuclear | 1150 | November 1986 |
| Central Maine Power Company | Sears Island #1 | N | Nuclear | 1150 | November 1986 |

Station Types: IF - Intermediate Fossil; CC - Combined Cycle; GT - Gas Turbine; N - Nuclear

## 4.03 - List of Alternatives*

System capacity and energy requirements can be met by a direct generating facility, such as a thermal or hydroelectric generating plant, sometimes in combination with an energy storage device. Several different types of direct generating facilities have been proven in utility power supply applications, and a number of alternative types of facilities are in various stages of development. Practical application of the energy storage concept in power utility systems has been confined to the conventional pumped hydroelectric type of facility. However, there are a number of other methods of energy storage in various stages of development.

### 4.03.1 - Initial Compilation

Table 4.1 is a preliminary listing of alternatives categorized in terms of:

- Degree of development;
- Type;
- Mode of operation.

Generation and energy storage facilities have initially been grouped according to the extent to which the technology required for the construction and operation of the facility has advanced. The first group consists of those facilities that have been in general use for some time, such as hydro, conventional, thermal, nuclear, and gas turbines. The characteristics of these plants have been well identified and assessed through years of development.

The next group of facilities comprises those recently developed or presently in operation on a limited scale.

The final category consists of those facilities that are still in the design or prototype stage, with no significant actual commercial applications.

The normal mode of operation of each facility is indicated, whether base load, mid-range, peaking, or any combination of the three.

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* For general references, see page 4-60.

## 4.03.2 - Description of Alternatives

All generating facilities have certain basic similarities. Nearly all convert some source of potential energy into mechanical energy either by spinning turbines or in the case of internal combustion engines by means of a reciprocating action. The mechanical energy is then converted into electric energy by generators.

The fundamental difference between the various facilities is their basic energy source. For hydroelectric plants, the turbines are rotated by the flow of water. For conventional thermal and nuclear plants, the driving force is pressurized steam. The heat source for creating pressurized steam in conventional thermal plants is obtained from the burning of fossil fuels such as oil, coal, or natural gas. In nuclear plants, the heat source is obtained from the fissioning of nuclear fuels such as uranium.

Gas turbine plants also rely on thermal energy for driving turbines. However, instead of using steam to drive the turbines, they rely on the pressure of high-temperature gases obtained from burning fuels. Other innovative forms of energy conversion are in various stages of development, but at this time none are in commercial use to any significant extent.

With the exception of hydroelectric plants, the characteristics of the various alternative forms of generating facilities are generally independent of the selected site. Nevertheless, siting studies would be necessary to determine the optimum location for the plant in each case. Hydroelectric developments including conventional, pumped storage, and tidal plants, are site specific in that the available locations for such installations are limited and cost-power characteristics are unique to each facility.

The characteristics of the various alternative generating and storage facilities are discussed, and some of the more important technical considerations and impact of each noted in the following paragraphs.

(a) Facilities in General Use

(i) Conventional Thermal Steam Cycle

In a conventional thermal plant, the principal objective is to produce as much energy as possible for each unit of fuel burned. Over the years, with experience gained in boiler design and materials, the temperature and pressure of the steam has been increased to improve overall operating efficiency. A modern conventional thermal plant will convert approximately 35 to 40 percent of the chemical energy in the fuel to electric energy. Conventional thermal steam plants were originally designed to use coal as fuel. During the 1950 to 1970 period, an abundance of oil led to its emergence as the basic fuel. Boilers were designed to accept low-cost, low-grade oils obtained as refinery by-products. As a result, many plants were converted to oil burning.

However, this trend has been reversed due to a dramatic increase in the price of oil along with air quality standards requiring low sulfur oil.

A total of 11914 MW of conventional thermal capability is currently installed in the New England System.

- Coal-fired steam plants have been used for the generation of power from the earliest days of the utility industry. Current unit capacities range from a few thousand kilowatts to over 1,000,000 kilowatts. Technologically, they are well developed and proven. Coal-fired plants are generally used for base or mid-range load demand applications, although a few simplified peaking units have been built.

  There are some 400 square miles of coal deposits located in the Narragansett Bay area of Rhode Island and Massachusetts. However, no known mining activity has existed since the turn of the century. Also, the coal deposits are geologically classified as meta-anthracite. This is a high-carbon coal that approaches graphite in structure and composition. As such, it is usually slow to ignite and difficult to burn. In recent years it has had little commercial importance, and it is generally unsuitable for use in steam generating plants.

No coal-fired plants are planned in New England up to 1987, although some imports of up to 400 MW of oil and coal-fired base-load capacity are currently scheduled up to the end of 1986. If deemed appropriate, construction of a coal-fired station would probably be more economical in the southern New England area, as the transportation industry is more developed in this heavily populated region. However, significant economic and environmental problems arise in the associated particulate and sulfur dioxide emissions, solid waste disposal, and cooling water requirements of a single large station of this type.

- Oil-fired steam plants represent a large percentage of the generating stations currently in operation in the New England area. As with coal-fired plants, base-load and mid-range oil-fired stations have been in commercial operation for many years and are well developed technically. A major percentage of the oil consumed in New England is imported.* An oil-fired plant would therefore be susceptible to future oil shortages.

  A total of 1021 MW of oil-fired mid-range capacity was added to the New England System in 1975. A further 1160 MW is scheduled in 1976 through 1978. A total of 190 MW of oil-fired base-load capacity was retired in 1975, and a further 79 MW is scheduled for retirement by the end of 1981.

  Any additional oil-fired stations would probably be constructed either near the sea coast or near established pipeline routes for economic transportation of fuel. Particulate and solid waste environmental problems are less severe than with coal-fired stations. However, environmental considerations related to potential oil spills and cooling water availability would have to be examined.

- Natural gas-fired steam plants are already in use in the New England area, in similar applications to coal and oil-fired plants, though generally in smaller installations. Gas supplies

*"Mineral Industry Survey: Crude Petroleum, Petroleum Products, and Natural Gas Liquids", U. S. Department of the Interior, Bureau of Mines, January 1975.

are mostly imported into the area from foreign sources. As a result, plants are located in the vicinity of existing pipelines in the southerly New England States.*

Installations in areas other than these would require construction of new pipelines or ocean-going handling facilities in the coastal areas. Natural gas-fired plants would also be particularly susceptible to future natural gas shortages. Such units would have less severe environmental impact than either oil- or coal-fired installations, since noxious emissions are minimal.

No new gas-fired plants are scheduled in New England in the next ten years.

(ii) Diesel-Power Generating Plants

Diesel powered plants employ conventional reciprocating diesel engines directly coupled to electric generators. Diesel units may offer some benefits as reserve peaking capability, but are of course oil fuel dependent. Relatively high capital cost, approximately twice that of a gas turbine, and limited size, has led to their use in small peaking plants, generally in the 1 to 10 MW range. These may be installed within 2 to 3 years of the decision to proceed, and can be located close to the load center to minimize transmission costs. Other advantages of diesel units include their fast starting capability, uniformly high thermal efficiency through the load range, comparable with medium-size thermal plants. Environmentally, diesel plant noise levels and emissions have relatively minor impact.

Diesel capability in New England is currently 243 MW. A 5-MW diesel plant was added to the New England System in 1975, and a total of 10 additional diesel plants are currently under study. These plants, totaling 55 MW of capacity in single additions of 12 MW or less, are scheduled from 1976 through 1985. Two plants of approximately 4 MW total capacity are scheduled for retirement by 1984.

* "Major Natural Gas Pipelines", Oil and Gas Journal Publ. Co., March 1974.

(iii) Gas Turbines

A special version of the jet engine, initially developed for the aircraft industry, has in recent years been progressively modified for industrial and power generation purposes. In essence, the industrial gas turbine comprises a jet engine driving a generator which may have a capacity in the range of 5 to 100 MW.

This type of generation has been increasingly used since the 1950's for stand-by and cycling operation, largely because of low capital costs, and short lead times. Because of high fuel costs, however, such units are normally used only for peaking duty, with operation restricted to an annual capacity factor of 5 percent or less. Such plants are susceptible to oil shortages.

A gas turbine set is normally installed close to the load center to minimize transmission costs.

Simple or non-regenerative open cycle turbines are less efficient than steam plants. For a higher first cost, the efficiency of a gas turbine may be increased by means of the regenerative open cycle system in which heat is recovered from exhaust gases and transferred to the incoming air stream.

There is a total of 1,489 MW of simple cycle gas turbine generator capability in New England at the present time. Generally these stations are individually less than 50 MW in capacity.* A new MMWEC** plant of 120 MW capacity has been approved for commercial operation by 1983. Two other plants are currently under study:

1980 - Cannon Street: 85 MW
1981 - Waters River: 20 MW

Environmental problems are generally minimal for such plants. Noise can be controlled to low levels, and gaseous emissions, primarily nitrogen and sulfur oxides, are generally low.

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* Directory of Electric Utilities, Electrical World, 1975/76.

** Massachusetts Municipal Wholesale Electric Company.

(iv) Hydroelectric

In a hydroelectric installation, a flow of water under a sufficient pressure differential or head rotates a hydraulic turbine directly coupled to an electric generator.

The essential requisites of a hydroelectric power plant are:

- A dam across a water course;
- A reservoir to impound the water;
- A waterway to convey the water to the power plant;
- A power plant to house the turbine and generator.

Such plants are dependent upon the availability of an adequate supply of water and upon a topographical configuration suitable for impoundment of the reservoir and development of the required head. Such sites are relatively scarce and development of them usually costly. Operating costs of a hydroelectric plant are low in comparison with equivalent thermal plants. When the available continuous flow is relatively low, such as is the case in New England, hydro plants are usually operated in the mid-range or peaking modes.

There is currently 1288 MW of dependable hydroelectric power capacity developed in New England in a total of 244 plants. In Maine, one 2-MW plant is scheduled for retirement in 1978, and a new 12-MW plant is under study to be on line in 1980. Identified undeveloped sites and existing plant expansions are estimated to amount to a total additional undeveloped capacity of over 2,500 MW, excluding the Dickey-Lincoln School Lakes Project.*

However, this capacity is an aggregation of a large number of relatively small developments. Approximately 1000 MW of capacity is available

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* "Hydroelectric Power Resources of the U. S., Developed and Undeveloped", Federal Power Commission, January 1972.

in six of these developments with individual capacities of 90 MW or more. The capacity and average annual available energy from each of these sites is as follows:

- Pierce Pond, Kennebec River, Me.: 180 MW; 380 Gwh
- Pontook, Androscoggin River, N.H.: 263 MW; 149 Gwh
- Livermore Falls, Pemigewasset River, N.H.: 230 MW; 78 Gwh
- Williamsville, West River, Vt.: 145 MW; 84 Gwh
- Cold Stream, Kennebec River, Me.: 90 MW; 260 Gwh
- Enfield Rapids, Ct.: 90 MW; 260 Gwh

The economic, social, and environmental impact of a hydroelectric development is generally quite considerable. There is no air or thermal pollution, but a reservoir inevitably causes disruption of the natural ecology of the water course and surrounding area in terms of water, land, and social resources. Additionally, hydroelectric sites are often far removed from the load centers, necessitating long transmission corridors for delivery of power to the system. On the credit side, hydro power utilizes a renewable resource, and reservoirs may have beneficial impact on flood alleviation and recreation.

(v) <u>Nuclear Steam Cycle</u> (LWR, HWR)*

Nuclear generating plants are similar in principle to conventional thermal plants, and are generally operated as base load units. The primary difference is the fuel used to generate the heat required. In conventional plants, a fossil fuel is burned. In a nuclear reactor, the heat is generated by the fissioning or

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* Combustion, Volume 46, No. 12, June 1975.

"splitting" of the uranium atom. As a result, the design of steam turbines, condensers, and generators for modern nuclear plants is a development of corresponding designs in thermal stations. Steam temperatures are usually lower in nuclear plants, and overall generating efficiencies are typically about 20 percent lower as a result. The amount of waste heat per unit of generation is thus approximately 20 percent higher than for conventional thermal plants.

Nuclear power technology has undergone major development in recent years, with various systems being developed in the United States, Canada, and the United Kingdom. The most important features of a nuclear steam supply system are:

- Uranium isotope, $U_{235}$, a material which has the property of fissioning into simpler products when it absorbs thermal (or slow) neutrons. This is accompanied by the release of heat energy which is the basic source of thermal energy for producing high-pressure steam.

- The moderator, a device to slow the emitted neutrons so that the chances of fission occurring in the reactor are increased. The moderator is required to slow the neutrons without reacting with or absorbing them.

- Neutron absorbers, which control the chain reaction by removing neutrons from the reactor. By means of control rods that can absorb neutrons, the chain reaction can be stopped altogether if desired.

- Primary coolant, to transport thermal energy from the reactor. The energy may be exchanged to a conventional thermal power cycle in a heat exchanger. In some reactors, the primary coolant is used directly for driving the power turbines.

Different materials and designs are used for achieving each of these four functions. Systems normally used in the United States rely on enriched uranium. For such facilities, a major portion of the fuel cost arises from the enrichment process. The CANDU* system, developed in Canada, uses natural uranium fuel which is processed directly from uranium ore and contains 0.7 percent of fissionable $U_{235}$.

In commercial U. S. plants, the moderator is ordinary (light) water. For neutron absorption, the most common materials used are boron compounds, cadmium, and aluminum.

The LWR system includes both pressurized water (PWR) and boiling water (BWR) reactors. The LWR systems have been in commercial use in the U.S.A. for some ten years.

In New England considerable reliance has been and is planned to be placed on nuclear plants. In 1975, the 393 MW Millstone #2 plant came on line, increasing the total nuclear capacity to 3364 MW. Millstone #2 is scheduled for rerating to 830 MW in 1976, and eight more plants totaling 9230 MW are now authorized by NEPOOL through 1986:

| | |
|---|---|
| - 1981 - Seabrook #1: | 1150 MW |
| - 1982 - Millstone #3: | 1150 MW |
| - 1982 - Pilgrim #2: | 1180 MW |
| - 1983 - Seabrook #2: | 1150 MW |
| - 1984 - NEPCO #1: | 1150 MW |
| - 1986 - Montague #1: | 1150 MW |
| - 1986 - Sears Island #1: | 1150 MW |
| - 1986 - NEPCO #2: | 1150 MW |

Nuclear plants create minimal air pollution. Nevertheless, environmental problems can arise in the disposal of radioactive wastes, thermal pollution of cooling water sources, and the social impact of such plants on the public at large.**

It is noteworthy that the reserves of uranium fuel for nuclear fission reactors in the

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* CANDU is an abbreviated form for CANadian Deuturium Uranium.

** "Decision Guidelines for Power Facility Siting in New England", The New England Regional Commission, 1975.

United States are not infinite. Current estimates indicate that known sources will be depleted by the year 2000 or earlier.* Nuclear breeder reactors offer an alternative which creates additional fuel as it produces heat for electricity. Breeders are currently still under development, as described elsewhere in this Section.

(vi) Power Purchases

In 1975 Firm Purchases of power by NEPOOL from outside the NEW England area** amounted to:

| | Summer | Winter (Dec.) |
|---|---|---|
| Firm Purchases (MW) | 217 | 226 |
| Total Capability (MW) | 18901 | 20212 |
| Ratio $\frac{\text{Purchases}}{\text{Capability}}$ (%) | 1.14 | 1.12 |

There is undoubtedly some added flexibility in retaining such a relatively small portion of the capability reserve margin in the form of power purchase arrangements. The availability of such power sources outside the New England area must of course be firm. With the current uncertainties in the power supply industry, the future availability of large blocks of power for purchase from utilities outside the area must be considered somewhat speculative. Nevertheless, it is likely that neighboring utilities will have relatively small amounts of power available for export.

Table 4.4 indicates the projected Firm Purchases outside the New England area to the winter of 1986/87. A total of up to 400 MW of this purchased power is oil or coal-fired base load capacity which is scheduled to be discontinued by the end of 1986. It does not appear appropriate to project purchases beyond 1986/87 at

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* "Uranium Resources to Meet Long Term Uranium Requirements", M. F. Searl, Combustion, May 1975.

** New England Load and Capability Report, 1975-1986, January 1, 1976.

this time. However, for planning purposes, it seems reasonable to assume that at least 200 MW of power will continue to be purchased from outside the New England area.

It is not known at this time what form these future purchases will take. However, for planning purposes, it has been assumed that the bulk of this power will be conventional thermal steam cycle generation.

TABLE 4.4

PROJECTED NEPOOL FIRM POWER PURCHASES (MW)

| | Summer | | | Winter | | |
|---|---|---|---|---|---|---|
| Year | Firm Purchases | Total Capability | Ratio (%) | Firm Purchases | Total Capability | Ratio (%) |
| 1976/77 | 426 | 21133 | 2.02 | 594 | 22158 | 2.68 |
| 1977/78 | 594 | 21509 | 2.76 | 594 | 22212 | 2.67 |
| 1978/79 | 594 | 21501 | 2.76 | 596 | 22799 | 2.61 |
| 1979/80 | 596 | 22103 | 2.70 | 599 | 22802 | 2.63 |
| 1980/81 | 599 | 22106 | 2.71 | 601 | 22804 | 2.64 |
| 1981/82 | 601 | 23258 | 2.58 | 602 | 24225 | 2.49 |
| 1982/83 | 602 | 24639 | 2.44 | 603 | 26676 | 2.26 |
| 1983/84 | 603 | 27054 | 2.23 | 605 | 27828 | 2.17 |
| 1984/85 | 605 | 27056 | 2.24 | 606 | 28979 | 2.09 |
| 1985/86 | 606 | 28207 | 2.15 | 405 | 28778 | 1.41 |
| 1986/87 | 405 | 28006 | 1.45 | 205 | 30878 | 0.66 |

(b) Energy Storage Systems*

There are, in principle, many different forms of energy storage. Fossil fuels (such as oil, coal, and natural gas), may be considered as storing energy in chemical form, which may be transformed into heat energy by burning. Heat may in turn be further transformed into mechanical energy by spinning steam turbines, and ultimately converted into electric energy by means of generators. Water

* "Review of Energy Storage Systems", Draft Report, Public Service Electric and Gas Co., February 1976. "Energy Storage: Applications, Benefits, and Candidate Technologies", F. R. Kalhoumer, EPRI, October 1975.

contained in reservoirs and head ponds is also a form of potential energy which may be converted into the mechanical and electric energy forms generated in a conventional hydroelectric plant.

There are, however, special types of energy storage facilities which are of importance to the power utility industry. The characteristic feature of these facilities is that both input to and output from storage is in the electric form. Energy is absorbed from the power system during periods of low demand, and returned later to help meet system peak demand.

In Europe in the early 1950's, energy storage facilities such as pumped hydro were incorporated in some electric utility systems which comprised mostly conventional thermal generation. As noted earlier, thermal plants generally operate more efficiently as base-load plants than peaking plants. Consequently, it became more economic to operate such facilities as base-load plants and to store the surplus energy produced during periods of low demand -- for example, late at night and on weekends. This stored energy could then be released at an appropriate time to help meet peak system demands.

In recent years, energy storage plants have become a significant feature in power systems. The capital costs of nuclear generating facilities are high, but operating costs are low. Such facilities also have poor cycling capability. Nuclear facilities are therefore better suited to base-load operation utilizing energy storage plants to absorb surplus low-cost energy and so maintaining the nuclear facility at full output. The stored energy is then released to the system at times of peak demand, thereby displacing costly and inefficient thermal peaking equipment.

Currently, pumped-hydro is the only form of energy storage developed for commercial operation.

- Conventional Pumped Hydro is widely used in electric utility systems. During the past decade, pumped storage has advanced from relative obscurity in North America to its present significant role in the production of peak and mid-range power.

The operating principles and basic requisites, the reservoir, water passages and power plant, are essentially the same as for a conventional hydro plant. However, the plant operates on a cycling basis and is capable of both generating and pumping. The water stored in the upper reservoir is released to generate power during peak demand. An additional lower reservoir is required for retention of the water discharged during the generating cycle, for subsequent return to the upper reservoir by pumping.

Because of pumping and generating inefficiencies, there is a net loss in energy production from a pumped storage plant. A pumped storage plant normally generates only 65 to 75 percent of the energy used for pumping. The economy results from the conversion of low-cost, off-peak energy to high value peak energy.

The social and environmental impacts of a pumped hydro plant are characteristically similar to those of a conventional hydro plant, but not necessarily on a similar scale. It is often not necessary to create a large reservoir on an existing water course, particularly if the head is high. Replensihment water need only be limited to relatively small amounts of seepage and evaporation losses. However, pool fluctuations are normally more severe.

Two major pumped storage projects are currently operational in New England, Northfield Mountain, 1000 MW and Bear Swamp, 600 MW. In addition, the Rocky River pumped storage project in Connecticut, in operation since 1929, was the first project of this type in North America. There are no known plans for construction of additional plants other than the Dickey-Lincoln School Lakes Project, which integrates conventional and pumped-storage hydropower and the Passamaquoddy tidal power development with reversible turbine units.

A total of 52 potential sites for conventional pumped storage ranging in size from 275 MW to 7930 MW have been identified in New England.* Of these, 14 preferred sites ranging from 1000 MW

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* "An Environmental Reconnaissance of Alternative Pumped Storage Sites in New England", New England River Basins Commission, July 1973.

to 7930 MW have been evaluated environmentally and ranked. The following four sites are considered to have the least on-site environmental impact:

| | |
|---|---|
| - Great Barrington #2, Mass.: | 1300 MW |
| - Fall Mountain, N.H.: | 1000 MW |
| - Percy #3, N.H.: | 3400 MW |
| - Site Leo, Me.: | 1450 MW |

(c) Facilities Developed But in Limited Use

(i) Combined Cycle Thermal

In recent years, hybrid gas turbine/thermal generating or combined cycle units have received increasing attention, especially for mid-range operation. In these plants, gas turbine exhaust possessing a high heat content is used to raise steam for a conventional thermal cycle.

To increase the power output of the steam turbine, additional fuel may be burned in the exhaust, upstream of the boiler. Addition of this thermal power cycle to the gas turbine substantially improves the overall cycle efficiency with the result that these units compare favorably with conventional thermal plants. The combined cycle system has better load-following characteristics for mid-range duty than conventional thermal plants, but is susceptible to oil shortages.

The combined cycle system is a combination of two proven technologies, gas turbines and steam generators, and as such is readily available. It is a fairly recent development in the power industry, and only a few units have been installed. At the B. F. Cleary #9 plant in Massachusetts, a 90-MW plant was brought on line in 1975 and a further 20 MW is scheduled in early 1976. Other developments currently planned are:

- Late 1976 - Potter: 95 MW
- 1981 - Stonybrook: 270 MW
- 1984 - MMWEC: 180 MW

The environmental constraints associated with the siting of a combined cycle plant in New England would be similar to those for fossil fired installations. Noise can be effectively controlled, and the particulates and solid wastes produced are minimal with the primary emissions being oxides of sulfur and nitrogen. Plant sizes range from 30 MW to 500 MW, with multiple unit installations possible for even greater capacity.

Lead time for a large (greater than 100 MW) combined cycle unit is approximately five years from inception to commercial operation. However, construction of combined cycle units may be staged so that the combustion turbine portion of the plant is available for peaking service while the steam portion of the plant is being completed.

(ii) Geothermal*

Geothermal energy results from the release of heat from within the earth's core. Such releases occur naturally in the form of volcanoes and hot springs.

Several generating plants have been developed near these naturally occurring heat sources, in Europe and North America.

Capacities are generally of the order of 400 MW, such as that at the Geysers in California.** Future larger developments are planned for up to 2870 MW.

Geothermal energy is available as heat in the form of steam and/or hot water. As steam,

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* United Nations Symposium on the Development and Utilization of Geothermal Resources, Pisa, Italy, 1970.

** "Economics of the Geysers Geothermal Field", California, D. A. McMillan, Jr.

preferably in the dry form, the energy may be harnessed directly to drive a steam turbine and an electric generator.

The use of hot water as an energy source is still in the research stage. Systems have been proposed to use hot water to boil secondary fluids such as isobutane to drive turbines. However, the high mineral content of the effluent water is a potential environmental hazard, and it must either be treated or reinjected into deep wells.

Geothermal energy is not restricted to natural surface sites. Hot rock can be found at depth at any location. In many parts of the western United States, for example, temperatures of the order of 600 degrees F are estimated to occur within 20,000 feet of the surface. Water could be injected into the well and recovered as hot water or steam, although such developments may well prove to be very expensive.

The steam at the California Geysers has low pressures and temperatures -- 100 psi at 400 degrees F compared with the 3,000 psi and 1000 degrees F steam used in conventional thermal generating plants. As a consequence, the turbines require about 450 MW of heat to produce only 100 MW of electricity*, an efficiency of only 22 percent, compared with 35 to 40 percent for conventional thermal plants.

Where natural sites exist, geothermal energy developments may be economically attractive on a large scale. Two potential sites near the New York/Massachusetts border have been tentatively identified,[1] but no information on the potential capacity of these sites is available at this time.

Geothermal power is currently still in the development stage, and many problems involving

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* "Energy and the Future", A. L. Hammond et al. 1973. Published by the American Association for the Advancement of Science, Washington, D. C.

mineral deposits in the machinery and corrosion have yet to be solved. Environmentally, significant noise, toxic gases, polluted effluent discharges, and potential ground subsidence would require consideration*. The long-term potential of geothermal development is therefore limited and would appear unlikely to replace either thermal or nuclear generation as a major source of electricity in the New England area in the foreseeable future.

(iii) Nuclear Steam Cycle (LMFBR, GCFR, LWBR)**

The clear limitations to the availability of uranium fuel for LWR and HWR nuclear plants has encouraged vigorous research into alternative nuclear generation systems. One alternative which has met with some success and is currently nearing the prototype stage is the "breeder reactor".*** In principle breeder reactors create additional fuel during the nuclear fission heat producing process.

Breeder reactors fall into four groupings:
- Liquid Metal Fast Breeder Reactor (LMFBR) utilizing plutonium and uranium 238, sodium coolant, and a fast neutron spectrum.
- Gas Cooled Fast Reactor (GCFR) utilizing plutonium and uranium 238, helium coolant, and a fast neutron spectrum.
- Light Water Breeder Reactor (LWBR) utilizing uranium 233 and thorium, light water coolant, and a thermal neutron spectrum.
- Molten Salt Breeder Reactor (MSBR) utilizing uranium 233 and thorium, fluoride salt coolant and a thermal neutron spectrum.

Further development of the molten salt reactor is questionable at this time.

The three remaining types of breeder reactor are in various stages of development at this time; the liquid metal fast-breeder reactor (LMFBR), the gas-cooled fast reactor (GCFR), and the light water breeder reactor (LWBR).

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* "Development of the Nation's Geothermal Energy Resources", P. Kruger, ERDA, Division of Geothermal Energy.

** Combustion, Volume 46, No. 12, June 1975.

*** "Energy for Survival", W. Clark, Anchor Books, 1975.

- Liquid Metal Fast
  <u>Breeder Reactor (LMFBR)</u>

  In the LMFBR, the coolant used is liquid sodium. This reactor is currently receiving the most attention in the U. S., and a large scale demonstration plant is scheduled for construction at Clinch River in Tennessee by 1980. The system has already been in economic operation in Europe for some 24 years, and is technologically proven. Economic feasibility of the system has not been shown as yet in the U. S.*

- Gas Cooled Fast
  <u>Reactor (GCFR)</u>

  The GCFR differs from the LMFBR in that helium is used as the primary coolant rather than liquid sodium. This system has not been proven technologically, and there are no known plans for such a development in the United States.

- Light Water Breeder
  <u>Reactor (LWBR)</u>

  The LWBR is essentially a modified PWR, using pressurized water as the coolant. The technology of the LWBR is thus well developed and final conversion and operation of the Shippingport nuclear plant in Virginia is scheduled for 1976.

(iv) <u>Tidal Hydroelectric</u>

A considerable flow of water and a significant head differential is often available where unusually high tides occur. The harnessing of tides for hydroelectric power generation has been contemplated for many years.

Tidal action is produced primarily by the varying gravitational pull of the moon and sun on the oceans as the earth rotates. The moon requires 24 hours, 50 minutes to rotate around

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* "Breeder Alternatives", L. J. Koch, <u>Combustion</u>, June 1975.

the earth. During this period it produces, in general, two high water levels at any given location. There are, of course, variations to this basic tidal cycle caused by a number of other factors.

The gravitational pull of the sun is about 46 percent that of the moon. As a result, the highest "spring" tides tend to occur when the moon and sun are acting more or less in unison, generally twice during each 29-day lunar month. During other periods of the lunar month, the gravitational pull of the moon and sun tend to counteract each other, causing low or "neap" tides to occur. Neap tides are typically only about half as high as spring tides.

With these and many other complicating factors causing tide variations, about 18 years elapse before a given tidal pattern repeats itself.

The harnessing of the tides for energy generation may be accomplished in several different ways. The simplest concept is to use a single-basin scheme in which the incoming tide is passed through gated channels into a storage reservoir for later release and power generation when the tide falls.

This method of operation is simple but relatively inflexible and allows generation for only about 30 percent of the time. Some improvement in operation may be achieved by provision of pumping capability to store additional water and create a greater head during the tidal inflow period.

A development of the single-basin scheme, or "single-effect" method of operation, is the "double-effect" generation mode. Special turbo-machinery is required which will operate with flows in either direction. An added benefit may be obtained by providing pumping capability in either direction of flow.

Another development is the double-basin scheme. In this a more continuous generating capability may be obtained by constructing high and low level basins with power plants between each basin, and possibly also between each basin and the ocean. Pumping capability would also provide added flexibility for the double-basin concept.

Only two known tidal power schemes have been developed: one on the Rance estuary in northern France, and one at Kislaya Guba on the Barents Sea in northern USSR.

The Rance scheme has 10 bulb turbine units, each with an installed capacity of 24 MW making use of a tidal range of up to more than 40 feet*. The units are designed for reversible double-effect operation and are thus capable of pumping or turbining from the ocean to the storage basin or vice versa. Annual net energy production is 544 Gwh excluding pumping. The Kislaya Guba plant is an experimental twin 400-KW reversible pump-turbine installation utilizing a head range of 15 feet**.

In North America prime tidal power sites have been identified on the Atlantic sea coast in the Bay of Fundy, both sides of the U. S./Canadian border. The 2,176 MW Minas basin development in Canada was studied in detail in 1969***, but was found to be uneconomic. However, studies have recently been reactivated.

The Passamaquoddy and Cobscook Bay schemes on the coast of Maine have been periodically studied since 1924. In a report published in 1964****, the project was proposed as a double-basin scheme with a 50-unit 500-MW power plant

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* Water Power, January 1967. See also "Energie des Marces", R. Gibrat.

** Water Power, May 1974.

*** Atlantic Tidal Power Programming Board, "Feasibility of Tidal Power Development in the Bay of Fundy", Oct. 1969.

**** "The International Passamaquoddy Tidal Power Project", Report by Study Committee, August 1964.

between the upper and lower pools. The upper and lower pools were to be formed in the Bays of Passamaquoddy and Cobscook respectively. The proposed power plant units were reversible pump-turbines with a head range of up to 26 feet.

In a 1965 report by the U. S. Department of the Interior*, the Passamaquoddy/Dickey-Lincoln School combined project was shown to have a benefit/cost ratio of 1.19:1. The benefit/cost ratio for the Passamaquoddy project alone was less than unity, and the tidal scheme was consequently deferred. However, an economic update is currently being performed.

A tidal hydroelectric plant has many of the advantages and disadvantages of a conventional hydro plant; the capital investment required would be considerable. Operating costs would be low, although somewhat higher than conventional hydro due to marine corrosion problems. Careful consideration would be required of the ecological and social impacts of such a plant on the marine and coastal environments.

The future state of the tides can be predicted with considerable accuracy. Hence, the maximization of generation from a tidal plant is fairly straightforward. However, one of the principal difficulties in operating a tidal plant is that periods of peak generation frequently do not correspond with the period of peak demand, and some form of energy storage is inevitably required.

Nevertheless, double-effect schemes, which in effect have in-built storage, can be designed to provide some (but not all) firm capacity. This type of facility usually requires the sacrifice of some energy benefit to achieve the firm capacity benefit.

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* "Conservation of the Natural Resources of New England", Report by U. S. Department of Interior, July 1965.

(v) Batteries*

Batteries may be considered to be a form of fuel cell as described elsewhere in this section. Each comprises a fuel electrode or anode, an oxidant electrode or cathode and an electrolyte. These components together convert chemical energy from the reaction between the fuel and the oxidant into electric energy. In the fuel cell the reactants are held outside the reaction area and are brought into contact with the electrodes only when power is required. In the case of a battery the reactants are held inside the cell and are periodically recharged to keep the chemical process functioning. The lead-acid battery has been in small scale use for many years. A number of other systems are currently in various stages of development (see alternative (e) (i)).

- The lead-acid battery is predicted* to be commercially available in plants as large as 800 MW with up to 10 hours of storage by about 1990.

  For power system operation, a special inverter is required as part of the installation. This is needed during the generating mode to convert the direct current output into alternating current at the frequency and voltage levels required, and for the reverse cycle during recharging.

  To maintain conversion losses at low levels, high direct current voltages, usually in excess of 1000 volts, are required. In the generating mode batteries operate efficiently at low power levels and under partial load. However, turnaround efficiency for the recharge/generation cycle is only about 50 percent, so that overall operating costs would be relatively high.

  Environmentally, there are potential problems with battery plants associated with the

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* "Batteries for Energy Storage: Potential Applications and Alternative Technologies", J. R. Birk, Engineering Foundation Conference on Energy Storage: User Needs and Technology Applications, EPRI, February 1976.

** "Peaking Power Batteries for Electric Utilities", Berkowitz and Brown, Proceedings of the American Power Conference, Volume 37, 1975.

ultimate disposal of spent electrolyte and the danger of accidental spillage. Emission of air pollutants is negligible. Thermal pollution of waterways is not a problem because excess heat is usually vented to the atmosphere. Noise levels are also low.

Battery storage plants to be used in conjunction with excess base generation may be sited nearly anywhere sufficient land is available. There appears to be no reason such a plant could not be located in an urban area. Although land area requirements are relatively high, the greatest potential would appear to be in small to medium sized urban areas. Assuming mass production, capital costs, including land requirements, are eventually expected to be competitive with conventional energy storage systems.

(d) Experimental Generating Facilities

(i) Alternative Fuels

Much research is currently being undertaken into the manufacture and use of fuels other than coal, oil, and natural gas in conventional thermal plants. These alternative fuels include:

- Biologically produced methane;
- Synthetic gas from coal;
- Methanol;
- Hydrogen;
- Synthetic gas (chemical);
- Municipal waste;
- Wood.

Methanol, a chemical plant feedstock, may be manufactured by fermentation of wood pulp, or from waste natural gas from foreign sources. Hydrogen may be commercially produced by the electrolysis of water. Gas may be synthesized by means of chemical processing using one of a number of base materials such as coal, naptha, natural gasoline, liquid propane gas, kerosene, or methanol*. Coal gasification and other

* Hydrocarbon Processing, Gas Processing Handbook Issue, Volume 54, No. 4, April 1975.

synthetic gas production plants are predicted to be viable alternatives to conventional fuels in the future. However, with the exception of municipal waste, there are no known plans for commercial use of alternative fuels for power generation in New England at this time.

- Municipal Waste Fueled Steam Plants* are currently undergoing extensive development and the refuse fired boiler concept has rapidly advanced in recent years. A number of demonstration plants are already in operation. The system differs from the conventional coal-fired station primarily in that fuel processing and boiler waste removal systems are more complex and correspondingly costly. These systems also require greater consumption of the fuel due to the lower heat value of refuse compared with, say, coal.

  Large quantities of refuse are therefore required, which tends to limit the scale of installations. For example, a 600-MW plant would require some 8,600 tons of refuse per day, estimated to be that produced by a population of over 3,000,000.

  The system has produced unexpected environmental problems in the form of large quantities of particulate emissions containing high bacteria counts. On the positive side, valuable materials may be recovered in the fuel processing operation.

  Two 75-MW waste fuel peaking fossil plants are currently planned by MMWEC to be operational by 1980 and 1981 respectively.

- Wood-fired steam plants** are currently under study in conjunction with the lumber industry. Also, the Green Mountain Power Corporation plans to build a 50-MW plant requiring some 400,000 tons of wood chips annually.

  The nature of wood waste firing is such that transportation of the wood is uneconomic over any significant distance. Also, the availability

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* Business Week, February 16, 1976, "Power From Trash: A Solution with Problems".

**Business Week, March 15, 1976, "Power Plants Turn to Good Old Wood".

of wood wastes is directly dependent upon local lumbering activity. The quantities of wood required would suggest that plants larger than 100 MW would be impractical. Even then, it is more likely that wood wastes would be used by the lumber industry for power generation rather than by generating utilities.

(ii) Fuel Cells*

The principle of operation of fuel cells was first discovered in 1839. The first commercial development did not occur until 1959, and because of high cost, almost exclusively in military and space applications. They currently are being developed for commercial power utility applications.

The fuel cell is a device that converts the chemical energy released from a reaction between a fuel and an oxidant into electric energy. The components are those of a battery: an anode, a cathode and an electrolyte. However, unlike a battery, the fuel cell generates power only when the reactants are brought into contact, and does not require recharging.

The electrolyte is continually replenished, and the electrodes in the fuel cell remain unchanged because they serve only as catalysts for the reaction.**

By altering the type of electrolyte and electrodes, various types of fuels may be burned in a fuel cell. Those currently under investigation include methane (natural gas), oil, hydrogen, methanol, and gasified coal. Production of methanol from oil, gas, or hydrogen by means of a number of chemical processes is currently under study. Coal gasification is also still in its infancy. All these fuel processing plants would in the long run be sizeable and costly. The natural gas fueled cell is the most advanced at this time, but the long-term availability of this fuel is questionable.

* "Assessment of Fuels for Power Generation by Electric Utility Fuel Cells", NTIS Publication No. PB247-216, October 1975 (prepared by A. D. Little, Inc.).

**Energy and the Future, Chapter 17, A.L. Hammond et al, American Assoc. for the Advancement of Science, Washington, DC, 1973.

The efficiency of a natural gas fuel cell is competitive with that of a conventional thermal plant, i.e. about 40 to 50 percent. The efficiency remains good over most of its operating range -- from 100 percent of capacity down to only 30 percent of capacity. The efficiency is as good in power cells which are as large as 100 MW or as small as 25 kw -- unlike many other generating facilities which tend to become less efficient as they become smaller.

Fuel cells produce low emissions and operate quietly. They also provide considerable operating flexibility and are very reliable. They are thus suited for generation close to major load centers or for operation in remote areas.

There are currently no commercially available fuel cells. However, a number of experimental 12.5-kw natural gas fuel cells have been installed in the U.S. and Canada. A group of utilities in the U.S. is also investigating the commercial feasibility of fuel cells of the 26-MW size.*

Fuel cells appear best suited for peaking or intermediate duty and should be similar in cost to combined cycle plants in annual cost versus load time.**

However, the availability of fuel sources in New England could be a problem. Natural gas is not readily available nor is coal, and fuel cells currently appear to be most economically attractive in conjunction with coal gasification.

Thus, fuel cells still need much further development to prove their economic feasibility in a large power system, and there could still be fuel resource problems for New England. For these

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* "Use of Fuel Cells to Generate Electricity from Hydrogen", United Technologies Corporation, Power Systems Division, 1975.

** "Electric Utility Fuel Cell: Dream or Reality?", A.P. Pickett, Electric Power Research Institute.

reasons, fuel cells will not be considered as a viable alternative.

(iii) Magneto-Hydrodynamic (MHD)/Steam Cycle

The MHD generator works on the principle of ionization of gases at high temperatures to produce electrically conductive plasmas. This plasma is then passed through a magnetic field or "channel", inducing a dc voltage which must be converted to ac power.

The MHD steam cycle system is a form of combined cycle installation in which the MHD generator exhausts into a heat recovery boiler to generate steam to supply a conventional steam turbine and electric generator, in a similar manner to the combined cycle plant described earlier.

The system is still in the experimental stage in the U. S., although a demonstration plant has been operated in the USSR at low outputs. In the U. S. research program, the products of coal combustion are used as the plasma. Significant progress has been made with successful tests of components and advances in component life. No published data is yet available, but the current ERDA schedule is reported to include successful operation of an experimental test facility in Montana in 1980. A commercial size pilot plant is scheduled in the late 1980's, with commercial power production some years later. In New England, the non-availability of coal will probably preclude the economic use of MHD plants within the next 20 years.

(iv) Nuclear Steam Cycle (HTGR, Fusion)*

Two other advanced nuclear powered systems are still in the development stage. These are an advanced fission process known as the high temperature gas cooled reactor, and nuclear fusion.

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* Combustion, Volume 46, No. 12, June 1975.

- The High Temperature Gas Cooled Reactor (HTGR) is similar to the LWR but utilizes helium to transfer heat from the reactor to a secondary water loop. High temperature and pressure provide efficiencies which, unlike LWR systems, compare well with modern fossil-fired plants.

  An advanced concept (Brayton cycle) for the HTGR does away with steam generation and the steam turbine portion of the conventional and current HTGR designs. The helium which circulates through the reactor is expanded in gas turbines which drive electric generators. The helium is then recompressed and returned to the reactor, in a continuous closed cycle. Such a cycle is slightly less efficient than the steam cycle version of the HTGR, but has the advantage of a very low cooling water requirement.

  Development of the HTGR Brayton cycle in Japan has advanced to the point of testing a 50-MW pilot plant.

  In the U. S., development of these reactors has not reached the demonstration plant stage.**

- Nuclear Fusion is the most recent of all proposed future nuclear generating devices, the technical feasibility of which has still to be proven. In the fission process neutrons split the uranium atom to release bondage energy. In fusion, on the other hand, heavy isotopes of hydrogen such as deuterium or tritium are fused together to form helium with the release of enormous amounts of energy.*

  In order to sustain fusion reactions, it is necessary to maintain a high plasma density, extremely high temperature, and confinement time. To date only two of the three required conditions have been achieved simultaneously. The first production of fusion energy will be demonstrated in the early 1980's with demonstration of commercial scale scheduled for the latter half of the 1990's.***

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* Gas Turbine World, January 1976.
** "Nuclear Power Engineering", M. M. El. Wakil, 1962.
***"Current Status in the Outlook for Fusion Power", R. L. Hirsch, Combusion, June 1975.

(v) Solar

The sun is easily the most abundant source of energy available today. About $5 \times 10^{19}$ Btu of solar energy is transmitted to the continental United States each year. A 10-percent overall conversion efficiency to electricity would alone amount to 500 times current U. S. demand levels[2].

Practical application of solar energy is still limited but growing steadily. At the present time only the space industry has harnessed this energy to any significant extent for direct generation of electricity. Future potential applications of direct use of the sun's energy are:

- Heating and cooling buildings;
- Production of organic materials through photosynthesis (to be used as fuel);
- Direct generation of electricity.

Solar generation is particularly adaptable to heat energy storage concepts.

- Heating and cooling of buildings* may be achieved by means of solar collectors which may be integral with the roof structure. Solar collectors contain a black metal surface covered by one or more panes of glass which reduce heat loss. Heat may be held by water or air in the collector, and circulated directly through the building.

  A second method of heating buildings with solar energy is by means of heat pumps. Such machines consist essentially of a compressor, condenser, and cooling coils or an evaporator. Heat energy is absorbed at a low temperature level from outside a building and rejected at a higher temperature inside the building. A major advantage of these machines is their high operating efficiency, and they are already in limited use in North America. Heat pumps may also be used in the well known vapor compression refrigeration cycle which would have application in air conditioning of buildings.

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* "Solar Energy Technology and Applications", J. D. Williams, Ann Arbor Science Publishers, Inc., 1974.

There is considerable research being conducted at present on both types of devices, and there are several machines (heat pumps, in particular) which are now commercially available. Significant prototype demonstration projects are under way in several areas of the U. S., including New England.

- Production of organic materials is suggested as a method of extending the availability of fossil fuel resources for conventional power plants. The practicality of such a scheme, however, is questionable since existing organic wastes (i.e., garbage) could be recycled into useable resources. Although this method would probably cost more than growing the organic matter, it does have the major benefit of waste disposal.

- Direct generation of electricity from solar energy may be achieved by one of two methods. In the first case, solar radiation is used as the heat source in a thermal steam plant. Reflectors are used to concentrate solar rays to heat water to steam for driving a steam turbine. A demonstration plant of 100 MW capacity is currently being investigated for installation in California by 1985. Land area requirements and investment costs are high, and this method of generation is essentially limited to applications in the Southwestern United States.

  The second alternative is to use photovoltaic cells which are made of special materials to generate positive and negative charges by absorbing photons. Since each cell develops only half a volt, a large number of cells is required. Capital costs are currently high, efficiency is low (only about 10 percent), and operating life is short.

(vi) Wind

Generation of electricity from wind is relatively simple. The force of the wind turns a windmill, or aero generator, the shaft of which is connected directly to a generator. The traditional windmill rotates about a horizontal axis. In the past few years, a wind turbine has been developed which rotates about a vertical axis. It uses flexible blades, weighs as little as one-tenth of a conventional windmill, and can rotate at up to six times the speed of the passing wind.

The energy available from winds can be converted to electricity with an overall efficiency of 60 to 80 percent. However, wind energy cannot be concentrated in the same manner as water or solar energy, and the amount of power which can be produced at any given moment is unpredictable. As such, the wind is not a firm source of power, and wind generation must be considered in conjunction with an energy storage system. The electrolysis of water in conjunction with fuel cells is especially suited to this application.

The New England area has had a history of wind-power usage. The 1250-KW Grandpa's Knob generator, built in 1941, operated intermittently for four years*. As recently as 1950, there were 50,000 small windmill-powered generators in the midwestern United States alone. For the most part wind generators are confined to residences in remote areas**.

Vigorous research programs sponsored by ERDA, NASA, and other agencies are currently under way. Plans are presently being formulated for a utility demonstration wind generator in Massachusetts, but the ERDA schedule for wind power shows no commercial use of wind power until 1985. The first plant is expected to be in the Mid-West where wind power potential is greater.

The 100-KW NASA Plum Brook Station at Sandusky, Ohio, is currently in operation to assess the feasibility of wind power***. In this plant, a

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* "Energy and the Future", A. L. Hammond et al, 1973. Published by the American Association for the Advancement of Science, Washington, D. C.

** National Geographic, Volume 149, No. 6, October 1975.

*** "Preliminary Results of the Large Experimental Wind Turbine Phase of the National Wind Energy Program", R. L. Thomas & J. E. Sholes, NASA Technical Memorandum X-71796.

125-foot diameter propeller powers the generator atop a 100-foot tower. Current plans for the next wind generator specify a 1.5-MW capacity with a 200-foot propeller. The eventual capacity of wind power generators might reach as high as 20 MW. Proposals have also been made for installation of batteries of wind generators on towers floating in the ocean.

Capital costs of wind generators are high. Maintenance and operating requirements and costs are as yet undefined.

(e) Experimental Energy Storage Facilities

(i) Batteries (Advanced)*

The lead-acid battery is the only electrochemical device which could be developed sufficiently for commercial system energy storage applications within the next ten years. Other battery systems are also under development at this time but are less advanced. These include the aluminum or zinc/chlorine systems, iron ferric chloride and redox cells, the sodium/sulfur solid electrolyte battery and the lithium/iron sulfide fused salt battery. The latter two systems require operating temperatures of 570 degrees F and 750 degrees F respectively. A number of materials problems still remain to be solved and proven technical and commercial feasibility is not expected for at least 10 to 15 years.

(ii) Flywheels

Bearing and windage losses of conventional flywheels become significant in energy storage applications of the duration required in general utility systems.

New flywheel concepts to store inertial energy have been introduced recently. The problems of conventional flywheels have been circumvented by means of:

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* "Batteries for Energy Storage: Potential Applications and Alternate Technologies", J. R. Birk, EPRI Engineering Foundation Conference on Energy Storage, February 1976.

- Concentric hoop and radial rod concepts;
- Advanced anisotropic materials;
- Low friction bearings;
- Partial vacuum operation.

A number of basic materials problems remain to be resolved, however, and the technical and commercial feasibility of the flywheel storage concept are still unproven. Commercial use of flywheels is thus unlikely within the next ten years.

(iii) Super Conducting Magnetic Storage*

Very large electromagnets with "superconductive" windings have been proposed as a feasible means of energy storage. Superconductive materials have very low electric resistance, and as a result, induce low energy losses due to heat buildup.

The development of electromagnetic energy storage is still in the research stage, but results to date show considerable promise. Measured turnaround efficiencies are as high as 93 to 95 percent for an ac system, and 97 to 98 percent for a dc system.

Superconductive magnetic storage facilities also have rapid start-up and unusually good load following characteristics, with response times in milliseconds. As a result, they may in future be used as the ideal generating alternative for responding to sudden fluctuations in system demand. However, capital costs are currently expected to be very high relative to conventional systems.

Prototype electromagnetic storage units have to date not exceeded about 220 KWh of energy storage. For commercial use in power utility systems, much larger units would be required.

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* "Superconductive Energy Storage Indicator-Converter Units for Power Systems", H. A. Peterson, N. Mohan, R. W. Boom, IEEE Transactions on Power Apparatus Systems, Volume PAS-94, No. 4, July/August 1975.

Some major technical problems remain to be resolved. These include the design of cryogenic high-voltage insulation, high-current electrical leads into a cryogenic environment, and certain structural aspects of the magnet design.

(iv) Thermal Storage

High temperature thermal energy storage systems have been proposed for the augmentation of heating sources in conventional thermal power plants. The system would be fully integrated with the thermal plant and would provide for the storage of energy from the steam supply prior to its conversion to electricity. Operation of the steam supply at constant output with varying electrical output of the power plant would thus be possible.

Steam, water, oil, heat transfer fluids, and molten salts have all been considered as the cooling fluid. Storage of steam or hot water could be used in peaking applications in fossil-fired steam plants provided turbines are designed for additional flow. However, the use of oil, heat transfer fluids and molten salts in power plants leads to potential problems of contamination of the cycle. High temperature storage of steam or water requires high pressures, and consequently thick-walled storage vessels.

Although the efficiency of thermal storage is high, the capital costs of such systems would also be relatively high*. The systems extract heat from the same source to which they will return the heat, and thus could not be used independently. Because of the attendant complex control problems such plants would not be considered competitive with conventional energy storage installations.

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* "Review of Energy Storage Systems", Draft Report, ERDA/EPRI, February 1976.

(v) Underground Compressed Air Storage*

Underground compressed air storage has been discussed for some time as a peaking system, but has not been put into practice until this past year. The principle of the concept is the storage of air compressed by conventional equipment using low-cost energy during off-peak periods. This air is then released during peak periods to drive a conventional gas turbine plant.

The world's first plant is currently under construction in Germany. This plant uses existing compressor, gas turbine, and steam turbine components, but has a small storage capacity of only 580 MWh. Systems investigated in the U. S. to date have generally been directed towards a storage of 2000 to 3000 MWh or larger.

There are three potential storage methods for compressed air: mined hard rock cavities, solution mined salt cavities, and aquifers. The technology required for the equipment and mining of cavities for each of the first two systems is well developed and presently available. The aquifer or "bubble" concept is still under investigation. Each of these methods is the subject of a combined ERDA/EPRI study program due to commence in 1976, the culmination of which is planned to be the construction of a pilot plant in 1980.

The economics of compressed air storage has still to be proven. The capital costs in favorable circumstances would appear to be competitive with conventional energy storage plants**. However, the concept as currently being developed requires the use of petroleum based fuels with their attendant cost dependency.

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* "An Assessment of the Technical and Economic Feasibility of Compressed Air Energy Storage", J. B. Bush, et al. EPRI/ERDA Storage Workshop, December 1975.

** "A Thermodynamic and Economic Analysis of Compressed Air Energy Storage for Electric Utilities", E. D. Neuman, M.Sc. Thesis, Queens University, Ontario, Canada, Nov. 1975.

The air storage system may use either of two basic cycle types. The constant pressure method of operation involves the use of a column of water to provide hydrostatic compensation for mass content changes in the cavern. This type consequently requires a surface water storage reservoir. The constant volume or dry cycle type is less efficient but uses no water and operates at continually decreasing pressure during generation. The first system is presently applicable only to hard rock caverns, the second to both rock and salt.

The constant pressure air storage cycle has a high potential in New England from a siting standpoint as there is an abundance of appropriate rock formations in this region. These plants may be located close to the load center, and wherever a least impact site may be available for the surface reservoir.

The constant volume cycle is less efficient than the constant pressure cycle at the present level of machinery technology. This type is thus only considered a viable alternative where the cavern can be created or is available at relatively low cost. A solution-mined cavern is one possible storage type, but there are no sizeable salt formations in New England. There may, however, be a few mines available with suitable characteristics.

Environmental impacts requiring consideration include rock disposal, gas turbine emissions, occasional fog, and if cooling towers are used, drift deposition. Surface reservoirs required for the constant pressure type of plant also require consideration. However, the flexibility offered for siting an underground air storage scheme allows the selection of least impact sites for surface structures.

(vi) Underground Pumped Hydro

Underground pumped hydro utilizes essentially the same basic principles as conventional pumped hydro. The main exception is that the potential head is developed between an upper reservoir at ground surface and a lower reservoir located in a cavern excavated in rock at depth. At a site with appropriate rock conditions, the head that can be developed is dependent less upon topography than upon limitations imposed by available pump-turbine equipment. The underground concept is potentially more costly than conventional surface located pumped storage, but appears to be significantly less costly than other forms of energy storage such as batteries, flywheels, and superconducting magnetic storage. Underground pumped hydro also provides many other potential benefits such as siting flexibility, reduced transmission line costs, a high degree of reliability and availability, and reduced environmental impact.

The underground pumped hydro concept utilizes essentially proven components from conventional pumped hydro and mining technology assembled to provide a unique approach to bulk energy storage. The primary components are:

- The upper reservoir and other surface-located facilities;

- The shafts and tunnels forming the various accesses and water passages to the underground components;

- The power facilities, including the pump turbines and associated facilities and equipment;

- The lower reservoir cavern.

The objective is to minimize the required volume and hence the cost of cavern excavation for a given energy storage. To this end most concepts that have been developed place emphasis on maximizing the head developed. Total heads in the range from 3000 feet to 4500 feet have been proposed. However, the current limit of application of single-stage reversible pump turbine design is at a head of about 1800 feet. Progression beyond this head would require considerable research and development work on machinery, or adoption of a "multi-step" design incorporating one or more intermediate power plants.

Greater depths of power plant also lead to problems of cost and scheduling of the associated underground excavations. The results of studies to date suggest that, using current techniques for shaft sinking and development, there is no significant economic advantage to be gained in the adoption of heads much in excess of 3,000 feet.*

A 1,000-MW underground pumped hydro facility with 10,000 MWh of storage at a depth of 2,300 feet is currently planned by General Public Utilities in New Jersey. Studies for plants ranging from 500 MW to 2,500 MW, generally with 10 hours of storage, have also been undertaken by a number of other utilities in the U. S.

A significant amount of research is currently being conducted into the underground pumped hydro concept by such agencies as EPRI, ERDA, and the USBR, and it is evident that construction of a pilot plant will probably be undertaken by 1980.

The surface reservoir and power transmission lines are the only surface manifestations of underground pumped hydro plants. Disposal of excavated material is an important factor, but the environmental impact of such installations is far less significant than that of a conventional pumped hydro plant. There is an abundance of appropriate rock formations in the New England area. There is thus considerable flexibility for optimum location of an underground pumped hydro plant close to the load center and with a surface reservoir which would cause minimal impact.

## 4.04 - Selection of Alternatives for Evaluation

Possible alternative power generation and energy storage facilities which could be installed in the New England power system have been reviewed in the previous section. Turning now to the identification of those facilities best

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* "Underground Pumped Storage Research Priorities", Draft Report: Technical Planning Study No. TPS75-618, EPRI, March 1976 (prepared by Acres American Incorporated).

suited for examination as alternatives to the Dickey-Lincoln project in a planned program of system expansion the need to quickly narrow the field of possibilities, in order to reduce the problem to manageable proportions, must be recognized. To this end, a preliminary screening process, designed to eliminate those alternatives which, on the basis of all available information, do not present a viable alternative within the time frame set for the Dickey-Lincoln project, has been adopted. Those alternatives remaining after this preliminary screening, described in this section, have then been subjected to further evaluation and ranking on the basis of capital and operating costs, as described in Section 4.05. Detailed economic evaluation of the effect of the finally selected alternatives on total system costs is presented in Chapter 5.

### 4.04.1 - Preliminary Screening

In this preliminary screening two basic criteria for evaluation have been adopted; these are:

- Technical feasibility within the 1985-1990 time frame;
- Unit capacity in relation to system load demand.

(a) Technical Feasibility

Technical feasibility is defined in this study to mean that a facility is capable of being constructed in a chosen location, that the components of the facility are commercially available, that the systems within the plant are of proven design, and that the facility can be built to serve the need for power when it is required. Proposals for the Dickey-Lincoln School Lakes Project are currently based on commercial operation of the plant by 1986 or later. Those types of power generation and energy storage facility which are already in general use (Section 4.03 a and b) will obviously be accepted as feasible.

Considerable research and development work is in progress on a number of other alternatives as described in Section 4.03 (c) and (d). For purposes of this study, only those alternatives

TABLE 4.5

NEW ENGLAND SYSTEM CAPABILITY*

| Type of Installation | Mode of Operation | Actual Dec. 75 MW | Capability 1975/76 thru 1986/87: NEPOOL Authorized Additions MW | NEPOOL Planned Capability** MW | Proposed Additions Under Study or Planned MW | Proposed Gross Capability MW |
|---|---|---|---|---|---|---|
| Nuclear | B | 3364 | 8910 | 12371 | 1150 | 13521 |
| Conventional Thermal | B/M | 11914 | 1160(M) | 13062 | -- | 13062 |
| Net Power Purchases | B/M/P | 192 | 21 | 213 | -- | 213 |
| Combined Cycle | M | 90 | 385 | 475 | 180 | 655 |
| Hydro | B/M/P | 1288 | -- | 1273 | 12 | 1285 |
| Gas Turbine | P | 1489 | 120 | 1609 | 105 | 1714 |
| Diesel | P | 243 | -- | 243 | 44 | 287 |
| Pumped Hydro | P | 1632 | -- | 1632 | -- | 1632 |
| Fuel Cells | P | -- | -- | -- | 26 | 26 |
| Peaking Fossil | P | -- | -- | -- | 150 | 150 |
| TOTAL | | 20212 | 10596 | 30878 | 1667 | 32545 |
| Estimated peaking capacity (20%) | | 4000 | | 6000 | | |

* New England Load and Capacity Report, 1975-1986. NEPLAN, January 1, 1976.
** Including authorized reratings and retirements.

which are expected to meet fully technical feasibility criteria within the 1985-1990 time frame will be considered.

(b) Unit Capacity

The purpose of this criterion was to eliminate those alternatives which do not meet certain minimum unit size requirements consistent with the anticipated scale of system expansion in the 1985/1990 time frame. As can be seen in Table 4.5, the currently planned gross system capability in 1986/87 is 30,878 MW, an increase of approximately 10,666 MW over the actual installation as of December 1975. This corresponds to average annual increments, during the 1975 to 1987 period, of approximately 900 MW.

Currently, the total New England system comprises approximately 20 percent peaking capacity in the form of hydro, pumped storage, diesel and gas turbine units, the 80 percent balance of base and mid-range generating capacity being made up predominantly of nuclear and thermal units. On the assumption at this stage in the selection of alternatives, that the mix of generating capacity will remain essentially the same over the 1975 to 1985 time frame, then the required annual increment of peaking capacity in the 1985/1990 period is expected to be not less than 20 percent of 900 MW, i.e. about 200 MW, and the corresponding increment of base/intermediate capacity, not less than 700 MW. Having regard to the evaluation of differential costs within the context of a total system capacity of 30,878 MW a minimum capacity of 700 MW for base load plant, and 400 MW for intermediate load plant was adopted.

4.04.2 - Alternatives Rejected

Table 4.6 summarizes the reasons for the rejection of those alternatives not considered for more detailed examination. It is often not possible to be precise in forecasting the commercial availability of a suitably sized facility in the 1985-90 period, if that facility is still in the development stage. In such cases, the selection decision is not clear-cut

TABLE 4.6

ALTERNATIVES REJECTED

| Degree of Development | Alternative | Operating Mode | Proven Technical Feasibility? | Adequate Size? | Remarks |
|---|---|---|---|---|---|
| In general use | Diesel | P | Yes | No | Reject |
| Developed but in limited use | Geothermal | B | Yes | No | Neither technical nor economic feasibility proven in New England; Reject |
| | Nuclear (LMFBR, GCFR, LWBR) | B | Yes | Yes | Not likely to displace LWR by 1985/90; Reject |
| | Tidal | M | Yes | Yes | Economic feasibility not proven in New England; Reject |
| Experimental | Alternative Fuels | B/M/P | No | Yes | Not likely to displace conventional peaking plants by 1985/90; Reject |
| | Fuel Cell | P | No | Yes | Economic feasibility not proven; Reject |
| | Magnetohydrodynamic | M | No | Not Proven | Reject |
| | Nuclear (HTGR, Fusion) | B | No | Yes | Reject |
| | Solar | M/P | Yes | No | Reject |
| | Wind | M/P | Yes | No | Reject |

Table 4.6
Alternatives Rejected - 2

| Degree of Development | Alternative | Operating Mode | Proven Technical Feasibility? | Adequate Size? | Remarks |
|---|---|---|---|---|---|
| | Batteries (advanced) | P | No | No | Reject |
| | Flywheels | P | No | No | Reject |
| | Superconducting Magnetic Storage | P | No | No | Reject |
| | Thermal Storage | P | No | Unknown | Reject |

Abbreviations: B - Base-load plant
M - Mid-range plant
P - Peaking plant

on the basis of the two criteria described above. It must be recognized, however, that the projected date of commissioning is only ten to twelve years hence. For facilities of the scale demanded here, it is surely necessary to see clearly the convincing demonstration of technical and commercial feasibility within the next two to three years if the facility is to meet the required commissioning schedule as an alternative to Dickey-Lincoln.

### 4.04.3 - Alternatives Selected for Evaluation

The ten alternatives selected for further evaluation after preliminary screening are listed in Table 4.7 with brief commentary.

A further evaluation of some of these alternates is described in Section 5 in which capital and operating costs of comparable alternates are developed. This further evaluation eliminates from consideration those alternatives which are relatively more expensive either than the Dickey-Lincoln scheme or than other similar alternates which may be substituted.

TABLE 4.7

ALTERNATIVES SELECTED FOR EVALUATION

| Type of Facility | Mode of Operation | Remarks |
|---|---|---|
| **DIRECT GENERATION ALTERNATES** | | |
| Conventional Thermal Steam Cycle | B/M | Oil fired version only to be evaluated |
| Gas Turbines | P | -- |
| Hydroelectric | B/M/P | Accepted subject to cost comparison with Dickey-Lincoln (Section 4.05) |
| Nuclear Steam Cycle | B | LWR versions only to be evaluated |
| Power Purchase | B/M/P | Assumed conventional thermal steam cycle |
| Combined Cycle Thermal | M | -- |
| **ENERGY STORAGE ALTERNATES** | | |
| Conventional Pumped Hydro | P | Accepted subject to cost comparison with Dickey-Lincoln (Section 4.05) |
| Batteries (lead acid) | P | Accepted subject to cost comparison with conventional energy storage systems (Section 4.05) |
| Underground Compressed Air | P | Accepted subject to cost comparison with conventional energy storage systems (Section 4.05) |
| Underground Pumped Hydro | P | Accepted subject to cost comparison with conventional energy storage systems (Section 4.05) |

Abbreviations: B - Base-load plant
M - Mid-range plant
P - Peaking plant

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1. Project Independence Report, FEA, November 1974.

2. Research Progress Report FF-2, Fossil Fuel and Advanced Systems Division, EPRI, January 1975.

3. "Energy Alternatives -- A Comparative Analysis", CEQ·ERDA·EPA·FEA·FPC·DOI·NSF. May 1975.

4. "Decision Guidelines for Power Facility Siting in New England", New England Regional Commission, November 1975.

5. "Review of Energy Storage Systems", (Draft Report), ERDA·EPRI, February 1976.

# 5 - IMPACT OF ALTERNATIVES ON SYSTEM COSTS

The primary consideration in the assessment of the economic viability of a project is the cost of its alternatives. It is frequently possible to identify specific alternatives with which to compare the project, but the seasonal variations in output of a hydro project often makes direct comparison difficult. A further complication arises from the capability of a hydro project to produce both peaking and base load power benefits. To properly take into account these various features of the project, it is necessary to assess its economic impact in comparison with alternatives within the context of the total system costs, both capital and operating. Of primary interest is the "mix" of alternatives necessary to match the benefits of the project, and the effect that the project may have on the deferment of capital expenditures.

In Chapter 4, a list of alternatives to the Dickey-Lincoln Scheme for generation and energy storage facilities which would be appropriate for inclusion in future capability expansion plans for the New England power system is presented. The number of possible combinations of type, size, and scheduled installation of these alternates is very large. It is obviously desirable to determine the optimum system expansion program which will satisfy the main objectives of the plan, i.e. economy, reliability, and flexibility. In some senses these objectives may be in conflict and the determination of the optimum combination is a complex exercise.

In Chapter 5 the assessment of the impact of alternative system expansion plans on system costs in the years 1985, 1990 and 2000 is described. The main objective of this assessment is to determine the optimum mix of facilities and total annual costs in each of these years. A further objective is to compare the impact on system costs of expansion plans which both include and specifically exclude the Dickey-Lincoln School Lakes Project. In addition, the plan which includes Dickey-Lincoln will further investigate three possible variants of the proposed Dickey-Lincoln Scheme.

Chapter 5 is summarized in Section 5.01. In Section 5.02 the general approach to the optimization procedure is discussed and in Section 5.03 the available methods to perform the analysis are evaluated. The application of the selected method of analysis is described in Section 5.04 and the results of the analysis presented in Section 5.05. Discussion and conclusions drawn from these analyses are presented in Section 5.06.

## 5.01 - Summary

Because of the wide range of power generating and storage functions which can be performed by a hydroelectric facility such as the proposed Dickey-Lincoln Project, a meaningful comparison of economic benefits of the project with those obtained from alternatives can best be made by the examination of the total system costs with and without the project. For a power system of the size and complexity of the New England system, this examination is best performed with the aid of a computerized mathematical model which simulates the operation of the entire power system and allows the impact of many variables on system costs to be assessed.

Several different "simulation" models have been reviewed to determine their appropriateness for the study of system costs required. Of these various models the General Electric "Optimized Generation Planning" (OGP) model has been selected as an accurate and practical planning model.

Using the OGP program, system operation over the period 1981 to 2000 will be simulated, initially using the optimizing feature of the program which will allow identification of the "optimum" system expansion without Dickey-Lincoln. Once this optimum mix has been established, the program will be used to simulate system operation with the three currently planned alternative developments at Dickey-Lincoln. Depending upon the impact of load management on the shape of the project load duration curves, duplicate computer runs may be required to assess the effect on the system expansion program.

5.02 - Optimization Procedure

In order to evaluate the economic attractiveness of a project, it must be compared with its alternates. Most generating alternates are designed for a specific mode of operation in the system, for example, base-load, mid-range, or peaking operation. Economic justification of a specific facility in this case is usually a matter of direct comparison with the capital and operating costs of other alternates.

For hydro power developments, this is generally not a valid approach for several reasons:

(a) A hydro system typically produces a number of benefits from the same plant (e.g. Dickey-Lincoln benefits are 725 MW at 0.12 capacity factor, 105 MW at 0.40 and 20 MW at 1.00);*

(b) The amount of matching individual benefits is often so small that the least costly alternative is impractical (e.g. a 20-MW nuclear plant as an alternative to the base-load benefits of Dickey-Lincoln);

(c) The operation of a hydro system is dependent on river flows which are typically seasonal.

Thus, to properly analyze a hydro power development, the impact of the development on the whole power system must be evaluated. Such an analysis should be performed on at least a seasonal or a monthly basis. More detailed simulations (i.e. weekly or even daily) may be performed to define exact operating procedures, but such detail is not justified in a planning study looking a quarter century ahead.

The most illustrative method of analyzing a particular hydro development is to develop two system expansion programs -- without, then with, the given development. Such an analysis would commence with an existing or pre-defined system mix and determine the optimum expansion program in each case subject to pre-determined operational constraints. The total capital investment and operating costs for each expansion plan would then be compared either on an annual basis, or capitalized for comparison on a present worth basis, to determine the least costly plan. A computerized mathematical model is essential for performance of such analyses.

(a) Mathematical Models

A number of computer programs have been developed to carry out the vast number of calculations required in power system expansion analysis and to perform the optimization process. For these types of programs, the user specifies the initial capacity mix, the period to be investigated, the forecasted load, the various types of alternates that are available to meet the load, and the specific constraints within which the expansion plan is to be developed. The model then selects and schedules a combination of alternates to meet the load requirements, subject to the defined constraints, in the least costly manner.

The "with" and "without" expansion plans may be evaluated by means of this model to determine the least-cost case.

(b) Comparison of Alternates

For the final evaluation of the given project, it is important to use the correct economic comparison. One way is to compare total annual system costs on a year-by-year basis -- both with and without the proposed project. If the system with the project is less costly throughout the planning period, then the project is obviously attractive. Conversely, if the system with the project is more expensive in all years, then the project is unattractive.

It is possible that the analysis would not be that clear cut. For example, the system with the project could be less costly in some years but more costly in others. In such a situation, a more valid economic comparison would be between the total present worth of all costs for the two systems.

Although such a strategy provides a valid economic comparison, the results could be inconclusive. This could happen in the case of a project which is small in relation to the total system. Then, the economic comparison would be between a small difference in two huge numbers.

For further confirmation, it would be advisable to try to identify which generating alternates the

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* "Dickey-Lincoln School Lakes, Maine, Fact Sheet", U. S. Corps of Engineers, October 1975.

proposed project is actually competing with. That is, the bulk of the costs which is common to both systems would be screened out of the comparison. The resulting values for the two systems would then represent a benefit-to-cost type of analysis for the proposed project.

## 5.03 - Selection of Method of Analysis

The selection of a method of analysis within the basic objectives outlined in Section 5.02 will essentially consist of the selection of a generation planning computer model which will satisfy three basic criteria; the model should be:

(a) Flexible - it should allow for a varied combination of alternatives;

(b) Accessible - i.e. the model should currently be available and operable with minimum learning time;

(c) Reliable - i.e. the model should be actively maintained by its supplier and have been proven in similar applications.

### 5.03.1 - Available Mathematical Models

There are three basic groups of specialists known to be involved in system planning modeling:

- Power utilities;
- Computer software designers;
- Equipment manufacturers.

#### (a) Power Utilities

System planning in the New England area is currently the responsibility of NEPLAN, the planning arm of NEPOOL. Extensive use has been made by NEPOOL of computer software and hardware developed by the Power Systems Planning Department of the Westinghouse Electric Corporation. However, the models currently in use are more concerned with relatively short-term system operational problems rather than long-term system simulation and optimization. It is understood that the latter problem is the subject of software development currently in hand.

Many utilities work together with computer manufacturers or software designers to develop models best suited to their needs. Others develop their system models in house. However, utilities possessing operating models do not normally subscribe to the practice of making them available to users or system planners outside their own organization.

(b) Computer Software Designers

A number of commercial organizations operate in the area of development of system planning models, e.g. Systems Control Inc., Santa Clara, California, and Power Technologies, Inc., Schenectady, New York. However, it is the practice of these organizations to develop the mathematical model to suit the needs of a particular client. Such a procedure would be prohibitively expensive and time-consuming unless acceptable ready-made software were not already available.

(c) Equipment Manufacturers

The manufacturers appear to be the only available source of readily usable models for system planning. Two manufacturers of computer hardware are known to operate power system planning computer models on a time-sharing basis:

- General Electric Company
  Electric Utility Systems Engineering Dept.

- Westinghouse Electric Corporation,
  Power Systems Company

No other suitable models are known to be available. The General Electric and Westinghouse Companies have worked directly with several electric utilities in the development of capacity planning models. The capabilities of such available models are evaluated in Section 5.03.2.

### 5.03.2 - Model Selection

(a) General Electric Company

The utility planning capability of General Electric is contained in one program package called Optimized Generation Planning (OGP). It consists of three elements which perform reliability, investment costing, and production costing evaluations.

It simulates the operation of a system on a monthly basis over a 20-year period. It operates the system to minimize total costs. The optimizing feature of the package is that it automatically chooses the least costly alternative to meet the increasing load. The choice is based upon both fixed costs and operating costs (levelized over the next ten years).

The basic output from the program is an annual display of generation additions and total system charges (in both actual and present worth dollars). Optional output includes environmental data such as heat rejection, particulate emissions, etc. Another option is that OGP can be used without the optimizing feature to simulate a user-defined expansion sequence.

(b) Westinghouse Electric Corporation

Westinghouse offers three programs in their generation planning library:

- Generation Expansion Optimization;
- Generation Planning Capacity Model;
- Weekly Production Costs.

The first program, Generation Expansion Optimization, optimizes the expansion of a system over a 20-year period. It utilizes linear programming techniques to analyze the entire period at once instead of analyzing the system in sequential speps. It selects additional units from a user-provided shopping list to maintain a given reliability at the least system cost.

The basic output of the program is an annual summary of generation additions and total system charges (in both actual and present worth dollars).

The second program, Generation Planning Capacity Model, is strictly a simulation program. It models the system to determine the capacity requirements of the system and when unit additions should be made. It considers such factors as maintenance, forced outage rates, loss of load probability, etc. The user must provide the list of unit additions. The Capacity Model selects from the top of the list when more generation is needed.

Output from this program consists of detailed listings of reliability, fixed costs summary, and operating data for the third program.

The third program, Weekly Production Cost, evaluates the costs of fuel and operation and maintenance incurred by a system for up to 20 years. Costing is performed on a weekly basis from a load duration curve. The program dispatches units to minimize total operating costs yet still meets the load plus spinning reserve requirements.

(c) Evaluation

Estimated costs for use of GE and Westinghouse models are as follows:

| | GE | Westinghouse | |
|---|---|---|---|
| Initial set-up & familiarization | $3,400 | $2,700 | |
| First case run | $ 400 | *(a) | $1,750 |
| | | (b) | $3,500 |
| Succeeding runs | $ 100-300 | *(a) | $1,750 |
| | | (b) | $3,500 |
| Access | Remote Terminal | Pittsburgh | |

* (a) Capacity model/weekly production cost;
(b) Generation expansion optimization.

Dickey-Lincoln will have relatively little impact on the total generating system mix in New England. As such, it is not necessary to develop substantially different system mixes for both the with and without Dickey-Lincoln cases.

Also, the basic task is to compare total system costs for a given system both with and without Dickey-Lincoln, to illustrate either a positive or negative influence of the project. The important relationship to maintain is consistency in the development of the two system mixes. Although it is desirable to strive for "optimum" system configurations, this factor is less important. Of more interest is the relative costs of the systems rather than their absolute costs.

The Westinghouse Generation Expansion Optimization program is a powerful model, but the detail and costs cannot be justified for this type of study. Similarly, the use of the other two Westinghouse programs (to simulate and cost a system), is more justified in providing detailed operating information than in providing comparative planning information.

The General Electric package is sufficiently accurate for the required study. In fact, other utilities have successfully used the General Electric package for this same purpose of economic justification of a generation alternative. The GE package also provides environmental data not available in the Westinghouse model.

5.03.3 - Modeling Strategy

The General Electric Optimized Generation Planning model will be used in the analysis. The following techniques are based on its use.

(a) System Data

Since the model provides for a 20-year simulation, the calendar years 1981 to 2000 will be modeled. Use will be made of pertinent NEPOOL data as to the actual system configuration at January 1, 1981, and any future additions or retirements. Planned developments will not be included in the analysis unless they have been committed for construction. However, planned additions will provide a basis for the sizing of alternative units.

(b) Escalation and Discount

To obtain absolute present worth cost estimates for future alternatives, the choice of escalation and discounting factors is of great importance. However, for the analysis of alternatives, comparative costs are of more importance.

It will be assumed that escalation will affect all the alternatives equally in relationship to the discount rate. Thus, escalation and discounting factors will be neglected in the analyses. All cost estimates will be quoted in 1976 dollars.

(c) System Simulation

It is important to recognize at this time that the expected influence of Dickey-Lincoln will be small in relation to the total system. The

NEPOOL planned total capability in 1985/86 is 28,778 MW (Table 4.2), with 830 MW initial nameplate capacity, Dickey-Lincoln represents only 2.9 percent of this requirement. With an estimated load growth of 5 percent annually, the development of Dickey-Lincoln would not defer other capital expenditure by much more than one year. Thus, Dickey-Lincoln will not drastically alter the optimum mix of alternatives in the system.

Because the influence of Dickey-Lincoln is small in relation to total system mix, full use will be made of the simulation feature of the OGP model. That is, simulation runs will be substituted for optimizing runs. The optimizing feature of the model will be utilized to develop the basic system without Dickey-Lincoln. The system may then be adjusted as necessary to accommodate minor unit sizing or other preferences. In this manner, the "optimum" system without Dickey-Lincoln will finally be determined.

The "optimum" system with Dickey-Lincoln will be developed by manually substituting it in the existing system instead of some other planned expansions. This would be done for one planned development at Lincoln School (70 MW) and three planned developments at Dickey:

I - 760 MW conventional hydro;

II - 570 MW conventional and 190 MW pumped storage;

III - 570 MW conventional and 570 MW pumped storage.

All these cases will be simulated for an on-line date of 1986.

The expected number of computer runs is indicated in Table 5.1. Only two optimization runs should be required -- one for the initial system and one for a major pumped storage development at Dickey. The second optimization run will be required to determine if the system can actually support the off-peak pumping requirements. Also, for each case, two simulation runs will be required to develop the final system configuration.

All these computer runs are based on the same expected load growth pattern. However, with load management, this pattern could change. If only the load growth rate were affected, the optimum system mix of alternatives would not change appreciably. Thus, only one simulation run for each case should be required to develop a revised set of costs. However, load management could also alter the shape of the load duration curves. In this case, the same number of computer runs will probably have to be repeated since the mix of alternatives will probably be altered.

The mathematical simulation will be used to provide a table of total annual costs for both the with and without Dickey-Lincoln Systems. At this time, no further economic comparisons will be performed (such as present worthing or identifying the actual alternatives that Dickey-Lincoln displaces).

TABLE 5.1

EXPECTED COMPUTER RUNS TO ANALYZE NEW ENGLAND SYSTEM

| | Number of Computer Runs | | | |
|---|---|---|---|---|
| Type of Computer Run | Without Dickey-Lincoln | With Dickey-Lincoln Plan I | Plan II | Plan III |
| Optimization | 1 | 0 | 0 | 1 |
| Simulation | 2 | 2 | 2 | 2 |